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CENTRAL STATION APPLICATIONS PLANNING ACTIVITIES AND SUPPORTING STUDIES

Final Report

by

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I. INTRODUCTION

This report describes work carried out by The Aerospace Corporation under JPL Contract No. 955434, "Draft Central Station Photovoltaics Applications Implementation Plan". As is indicated by the title, the initial focus of the effort under this contract was on the development and drafting of an "implementation plan" (later renamed "requirements document") for those activities of the DOE National Photovoltaic Program that are directed toward the application of photovoltaic technology in central station (utility) power generation plants. When the major planning work had been completed, the emphasis of the project shifted to two principal supporting activities. The first of these was a program of data collection and analysis designed to provide additional information about the subset of the utility market that was identified in the plan as the initial target for photovoltaic penetration -- namely, the oil-dependent utilities (especially municipals) of the U.S. Sunbelt. The second supporting activity was a series of interviews designed to ascertain utility industry opinions about the National Photovoltaic Program as it relates to central station applications.

In the next section of this report, summary accounts are given of the central station planning work and of the two main supporting studies mentioned above. The following two sections then provide much more detailed accounts of the two supporting studies. (A more detailed discussion of the central station plan is, of course, presented in the planning document itself, "Central Station Applications Implementation Plan", Aerospace Corporation, 16 July 1979, which is being circulated in draft form within the Photovoltaic Program.)

In addition to the activities mentioned above, the effort under the contract included a number of activities in direct support of the Jet Propulsion Laboratory as Lead Center for Technology Development and Applications in the DOE Photovoltaic Program. These included participation in the Management Council, in a variety of program review meetings, and in the deliberations of several ad hoc committees. These were either short-term activities or were activities involving a number of other organizations and reported elsewhere. They are not further discussed in this report.

II. SUMMARY

A. Central Station Applications Requirements Document

The first draft of the Central Station Applications Requirements Document (originally called "Central Station Applications Implementation Plan") was completed on 1 June 1979. After review by the JPL Lead Center for Technology Development and Applications and by the various Field Organizations of the National Photovoltaic Program, a revised version was prepared and submitted in mid-July. This revised version was in the DOE review cycle at the close of the period covered by this report.

The document describes a plan for implementing those elements of the National Photovoltaic Program's Multi-Year Program Plan that relate to central station applications. It defines a broad-based but coordinated program of federal government activities that are designed to make photovoltaic central power plants a commercial reality by 1990 or before. These efforts are directed toward two somewhat different markets: 1) a limited market (oil-conservation market) in utilities that are located in high-insolation regions of the U.S. and are heavy consumers of oil for power generation and 2) the much larger market represented by general utility applications across much of the U.S. It is expected that photovoltaic power plants will be competitive in the first of these markets on the basis of fuel savings alone when total system costs are in the \$1.50 - 2.00/W_p* range but that system costs will have to be reduced to \$1.10 - 1.30/W_p in order to penetrate the larger market.

The plan is comprised of five key elements:

- An aggressive program of Advanced Research and Development is included that is aimed at the definition and exploratory development, to the point where technical feasibility has been demonstrated, of up to four collector concepts (flat-plate or concentrator) that have the potential of being manufactured

*All cost and price figures quoted in this report, unless otherwise indicated, are expressed in terms of constant 1980 dollars.

and sold at a price in the \$0.15 - 0.40/W_p range. (It is expected that, when collector prices are in this range, total system costs of \$1.10 - 1.30/W_p will be achievable). As technical feasibility is approached, a decision will be made as to when and how the concept should be phased into the technology development effort discussed below.

- Coordinated Technology Development activities will be directed toward reducing the cost of manufacturing critical components and subsystems by improving, streamlining, and automating the steps of the manufacturing process. Technology Development begins with production processes that have been shown to be technically feasible and ends with the demonstration that the product can be manufactured at a price consistent with program goals. The initial focus is on photovoltaic collectors based on technologies already known to be technically feasible (the "baseline technologies", i.e. flat plate single-crystal silicon modules and concentrating collectors using single-crystal silicon cells), together with the remaining balance-of-system components that are needed to fabricate a complete system. The goals of this effort are a collector price of \$0.70/W_p and a total system price in the \$1.50 - 2.00/W_p range. When advanced technology collector concepts are shown to be technically feasible, they also will undergo Technology Development, with the goal of reaching collector prices in the \$0.15 - 0.40/W_p range.

- Systems Engineering and Standards activities will be aimed at the definition of optimal system concepts and at the development of systems through the assembly and testing of breadboard and prototype systems and subsystems in controlled environments.

- A Test and Applications program is included in which complete (but subscale) photovoltaic central power plants will be assembled and operated. The first such experiments will be two 2-MW Initial System Evaluation Experiments (ISEE), designed to provide the first practical experience with the actual design, construction, and operation of a complete plant. These ISEE

projects will, however, use baseline-technology collectors that have been shown to be Technology Ready for production at $0.70/$W_p$. They will thus serve also as System Readiness Experiments (SRE) that demonstrate that it is technically feasible to build a complete system from components whose costs are consistent with the $1.50 - 2.00/$W_p$ total system cost that is needed to compete in the oil-conservation market. These initial experiments will be followed by SRE projects that use advanced technology collectors and are intended to demonstrate System Readiness for systems that could be constructed (if volume is sufficient) for $1.10 - 1.30/$W_p$.

- A diversified program of Commercialization activities is designed to 1) foster the production of critical components and subsystems in large enough volume to permit their sale at prices consistent with program goals, 2) demonstrate (through construction of Commercial Readiness Demonstration Projects, or CRDPs) that photovoltaic power plants can, in fact, be built at costs that are competitive, and c) promote the commercial construction of such plants once their Commercial Readiness has been demonstrated.

B. New Perspectives on Market Prospects for Photovoltaic Central Station Power Plants

The strategy for the central station applications activity, as summarized in the preceding section, was based in part on a number of independent analyses. These have indicated that the total cost of a photovoltaic power plant must be in the $1.10 - 1.30/$W_p$ range in order to be competitive in utility applications in most of the United States. This perception was responsible for the strong advanced-technology component of the planned activities and for the selection of 1990 as the commercial readiness target date for general utility applications. Some supplementary analyses were also carried out, however, that led to the general conclusion

that recent developments in the utility scene -- most notably, the sharp and continuing rise in oil prices -- gave reason to modify this perception somewhat. It was concluded that photovoltaic systems costing \$1.50 - 2.00/W_p would be competitive in the latter half of the 1980s in a small but important fraction of the utility market -- the heavily oil-dependent utilities, especially the municipals, of several Sunbelt states. It was for this reason that the central station applications plan specified that the first central station experiments use baseline technology collectors, which are expected to be technology ready (at \$0.70/W_p) by the time the experiments are fielded. (When collector modules costing \$0.70/W_p are available, it is expected that system costs in the \$1.50 - 2.00/W_p range will be achievable.)

When the draft Requirements Document was completed, time and resources were available to refine and extend these analyses of the Sunbelt oil-conservation market for photovoltaic power plants. Computations were made of the breakeven cost of a photovoltaic power plant vs. continued generation of electricity in an existing (and paid for) oil-steam plant, and it was again concluded that even fairly conservative assumptions about future escalation of oil prices lead to breakeven photovoltaic system costs in the \$1.50 - 2.00 range by the mid-to-late 1980s. Data were also collected on the magnitude of the market that would be opened up by the achievement of photovoltaic system prices in this range. It was found that the total consumption of residual oil in Sunbelt utilities where photovoltaic systems are competitive at \$1.60/W_p will be of the order of 50,000 barrels/day in 1986 and will rise to more than 400,000 barrels/day in 1990 if oil prices escalate at just 6%/year (in terms of constant dollars) over the period from 1980 until the year in question. If even a modest fraction of this oil consumption were made unnecessary by photovoltaic power generation, the benefit to the U.S. would be large. The effect on sales of photovoltaic modules, furthermore, would be enormous, and the resulting economies of production could be expected to lead to further significant price reductions.

A more detailed discussion of these supporting analyses and of the conclusions that were based on them is presented in Section III of this report.

C. Some Utility Industry Comments in Central Station Activities in the DOE Photovoltaic Program

The ultimate objective of the central station applications portion of the Photovoltaic Program, of course, is to induce commercial construction of photovoltaic power plants by the U.S. utility industry. The planned activities must therefore be acceptable to this industry and must provide the sort of evidence and information that it will require before including photovoltaic technology in its generation expansion plans. In an effort to obtain the benefit of the utility point of view while there was still time to adjust the plan accordingly, a group of structured interviews was held with representatives of several individual utility companies and of the Electric Power Research Institute. These interviews elicited a number of useful suggestions but did not reveal any major utility industry objections to the strategy and emphasis of the program. A detailed description of the interviews and of the comments made by the industry representatives is given in Section IV of this report.

III. NEW PERSPECTIVES ON MARKET PROSPECTS FOR PHOTOVOLTAIC CENTRAL STATION POWER PLANTS

A. Introduction

As a result of the inherent modularity of photovoltaic solar energy conversion, this technology can, with essentially equal facility, be used in roof-mounted systems serving the electricity needs of single households and in central station power plants delivering hundreds of megawatts into the utility grid. It is widely expected that significant commercial use of photovoltaic electricity will occur earlier in the first of these application areas than in the second, primarily because the lower effective cost of capital to a homeowner will permit him to pay a somewhat higher unit price for his system. The central station (utility) application, however, has a number of advantages that may well give it greater importance in the long run. Because of recent developments in the utility industry, furthermore, it now appears likely that photovoltaic power plants will become economically competitive in some portions of the utility market at an appreciably earlier date than had been expected. In the discussion that follows, the advantages of the central station application are set forth, along with some of the counterbalancing disadvantages, and an account is given of the new perspectives on the associated photovoltaic market that emerge from a consideration of the recent changes in the utility industry picture.

B. Advantages and Disadvantages of the Central Station Application

The principal advantage of applying photovoltaic technology to central station power generation is that this application represents the largest of all the potential photovoltaic markets and can result in the largest photovoltaic contribution to the U.S. energy supply. Since the utility industry currently uses central station generation to supply virtually all of the electricity consumed in the residential, commercial, institutional, and industrial sectors of the economy, a central station

photovoltaic power plant may be thought of as serving all of these market sectors. Serving these markets by injecting central station photovoltaic power into the utility transmission/distribution grid rather than at individual load points, furthermore, will require only minimal, if any, societal or institutional changes. Serving the same electric loads via dedicated on-site photovoltaic systems, on the other hand, will necessitate major shifts in the relations between utility and consumer and will require the development of a whole new commercial infrastructure to distribute, sell, install, and service the photovoltaic hardware.

From the point of view of ease of penetration, the central station market has the advantage that a single decision, involving only a relatively small number of people, can result in the deployment of a substantial amount of photovoltaic capacity. By contrast, to put into the field the same total amount of capacity in the form of roof-top residential systems would require decisions by tens of thousands of individual families.

It is also significant that the utility industry, as a customer for photovoltaic hardware, has a number of desirable characteristics. In comparison with other potential customers, for example, utility staffs have a high degree of engineering competence and should be able to adjust rapidly to dealing with the complexities of a fairly novel technology. System maintenance will also be considerably more straightforward for a utility than for other customers. Utilities are accustomed to dealing with such problems in a centralized and efficient manner, using full-time maintenance crews. It is also inherently more efficient to service a few large plants than many smaller, scattered systems. (In fact, servicing of on-site photovoltaic units may require the creation of an additional new service industry to complement the new manufacturing and distribution capability required for these applications.) These attributes, plus the already-noted utility company characteristic of centralized decision-making, would be especially important if a very rapid expansion of the U.S. photovoltaic capacity should be called for as a result of a catastrophic reduction in conventional generation capability (e.g., by a total cut-off of OPEC oil exports).

Finally, siting restrictions should be much less severe for a central station photovltaic plant than for an on-site system serving a specific load. A utility usually has plenty of rural land within its service area that is suitable for siting plants, whereas the owner of an on-site system is constrained by the availability of roof area or of open land adjacent to the load being served.

There are, of course, a number of respects in which the central station photovoltaic application is less attractive than the on-site residential application, especially in those cases where the on-site photovoltaic system is owned by the homeowner. As has already been mentioned, the homeowner can afford to pay a somewhat higher unit price (in dollars per kW) for a photovoltaic system because he can obtain capital at a lower effective cost. (It is assumed here that the photovoltaic system is treated, like a furnace, as an integral part of the residence and that its purchase is therefore financed as part of the overall mortgage arrangement. It is also assumed that the residence remains connected to the utility transmission/distribution grid and that the grid supplies whatever supplementary power is needed.) Because residential photovoltaic systems are much smaller than central station power plants, furthermore, the total cost of an individual unit is much smaller. For a given expenditure of public or private funds, a much larger number of units can be constructed and a much larger number of design variations can be tested in practice. Finally, if a residential photovoltaic system is engineered to operate independently when utility-generated power is unavailable, the possession of such a system could provide an added degree of service reliability to a home-owner since photovoltaic electricity could be utilized on those (admittedly rare) occasions when utility service is interrupted by a generation, transmission, or distribution outage.

C. New Perspectives on the Utility Market for Photovoltaic Systems

1. Background

In the interval since the 1973 beginning of the National Photovoltaic Program, a number of studies have been made of the central station application and of the requirements that a photovoltaic central power plant would have to meet in order to be competitive with conventional plants (Refs. 1-8). These studies have generally concluded that, even in the Southwest, the total cost of a photovoltaic plant, installed and ready to operate, would have to be in the $1.10 - 1.30/W_p$ range (in 1980 dollars), or less, in order to be economically competitive with fossil-fueled power plants. Achieving total plant costs in this range would require the availability of photovoltaic collector modules at a price (F.O.B. factory) of $0.15 - 0.40/W_p$. It has not been expected that such low module prices will be reached with the baseline technologies (flat plate or concentrator modules using single-crystal silicon cells) that are currently under intensive development. Although one of the DOE Program goals is to drive module prices down to $0.70/W_p$ by 1986 using one or more of these baseline technologies, it is not considered likely that much lower prices can be achieved in this way. It has therefore generally been concluded that the initial photovoltaic penetration of the central station market will begin after development of advanced technology collectors, which are expected to be commercially available in 1990 or shortly thereafter. The central station application, consequently, has been viewed as an intermediate or far-term, rather than a near-term, commercial prospect for photovoltaic power generation.

2. Recent Developments

The analyses behind the conclusions discussed in the preceding section were all based on the general assumptions that a) it would continue to be possible to construct nuclear, coal-fired, and oil-fired

plants without significant restrictions and at capital costs not too much higher than those experienced in the past and b) fuel prices would also escalate at fairly reasonable rates. As is well known, both of these assumptions have turned out to be invalid during the last several years.

Many obstacles have arisen to the construction of coal-fired and nuclear plants. Concerns about pollution of the environment have led to cancellations (e.g., of the Kaiparowitz plant in Utah) or delays of new coal-steam power plants, and doubts about the safety of nuclear power plants have brought construction of such plants virtually to a halt, nation-wide. These considerations have, at the very least, greatly increased the time required to bring either type of plant on line and have thus sharply increased the total capital cost. The associated uncertainties have led many utilities to postpone previously planned additions to capacity. Prices for coal and, especially, nuclear fuel have also begun to rise fairly rapidly.

The most spectacular changes, however, have been those affecting oil-fired power generation. Fig. 1 illustrates graphically what has happened to the price of crude oil over the past several years. As is indicated there, oil prices have been rising since 1973 at an average real escalation rate (expressed in constant dollars, i.e., over and above general inflation) of about 21%/year. While they clearly cannot continue to increase at this rate indefinitely, at the close of 1979 there is no indication of a levelling off.

This rapid increase in oil prices, of course, has been associated with, and largely caused by, a sharp increase in U.S. dependence on imported oil, much of it from politically volatile areas of the world. There has thus also been an increasing degree of uncertainty about availability of adequate supplies of oil for power generation and an increasing degree of utility vulnerability to supply interruptions. The impact of the U.S. oil supply problem on utilities, furthermore, has been heightened by the 1979 presidential directive calling on them to reduce their consumption of oil by 50% by 1990.

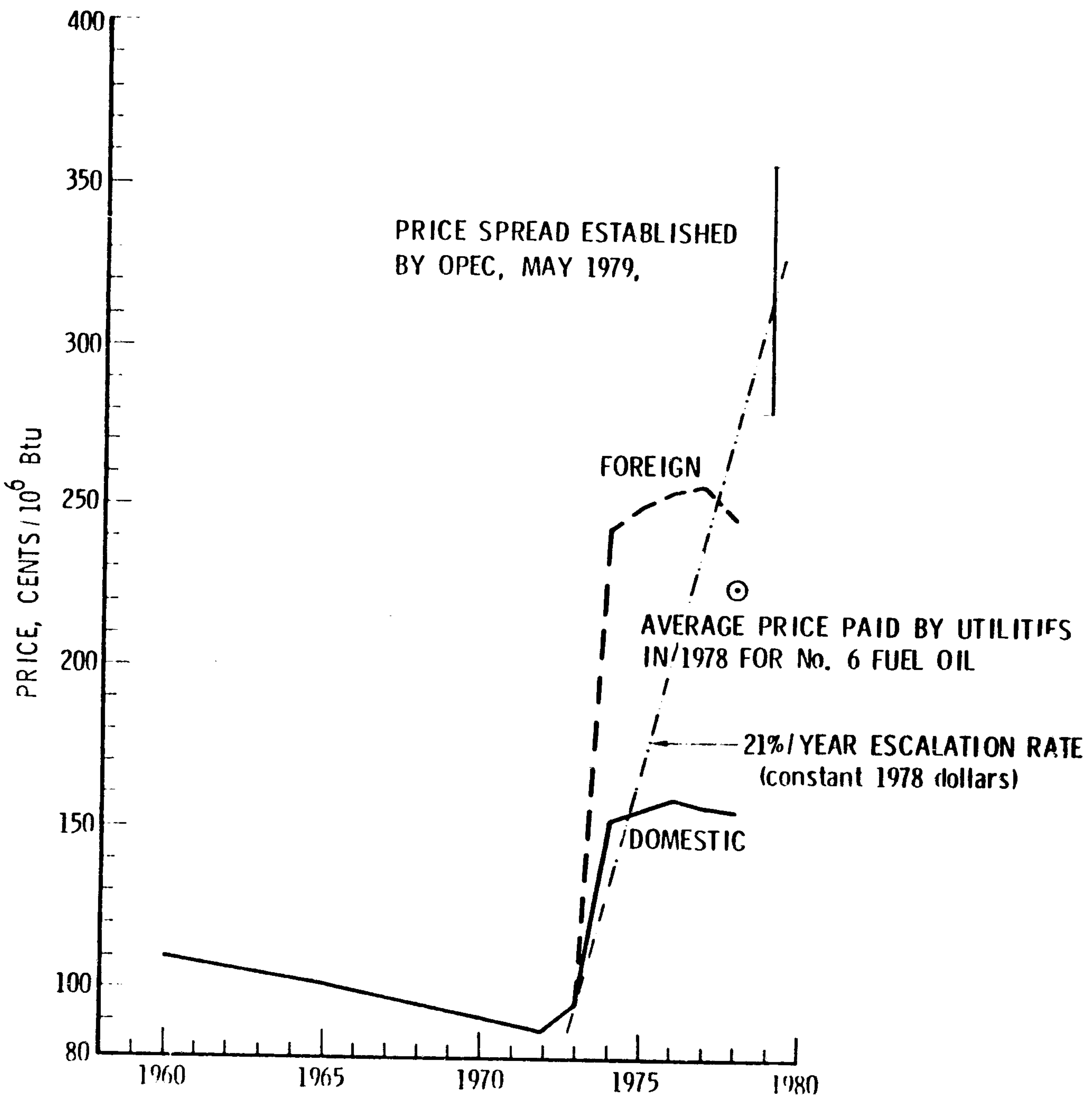


Figure 1

Yearly Average Crude Oil Price at Source (1978 Dollars)

In addition, oil price/supply problems influence the price and availability of natural gas as a substitute fuel. It appears, for example, that the legislation implementing the presidential directive mentioned above will include a provision also to reduce gas consumption for power generation by 50% by 1990.

Finally, the potential competitive position of photovoltaic central power generation is impacted by recent developments in the photovoltaic program. There has been rapid progress toward the program goal of reducing the price of photovoltaic modules to $\$0.70/W_p$ by 1986 through development of the baseline technologies mentioned in Section C. The technology development program is on schedule and there is currently every reason to believe that the goal can be met. System studies have indicated that when $\$0.70/W_p$ modules are available, it will be possible to construct complete central station power plants at a total cost of $\$1.50 - 2.00/W_p$. As is reported in the next section, construction of such plants may well prove to be a cost-effective alternative to the burning of oil for electric power generation by the mid to late 1980s.

3. Breakeven Photovoltaic System Costs vs. Oil-Fired Power Generation

The developments discussed in the preceding section have considerably altered the arena in which photovoltaic central power generation must compete. In particular, they have increased the likelihood that utility companies that are heavily dependent on oil at present will soon a) have an urgent need for generation capacity that does not consume oil (or, for that matter, gas) and b) experience difficulties in meeting this requirement with coal-fired or nuclear capacity. It is therefore clearly of interest to investigate the conditions under which photovoltaic generation could contribute to the solution of this problem.

To this end, a preliminary breakeven analysis was made of photovoltaic central power generation in this oil-conservation mode, i.e., substituting photovoltaic generation (in a newly constructed plant) for generation by the consumption of oil in existing plants. The breakeven

value of the total installed cost of a photovoltaic power plant was determined by equating the levelized annual cost (levelized in constant dollar terms) of owning and operating the photovoltaic plant (principally the annual cost of capital -- required return on investment -- and operation and maintenance costs) with the value of the oil saved during the first year of operation. In this computation, therefore, it is not assumed that any conventional generation capacity is displaced. The approach, furthermore, reflects a preferred, and conservative, photovoltaic purchase strategy in a time of rising (real) energy prices: continue to buy conventional energy (i.e., burn oil) until the cost is as great as the annual cost of owning a photovoltaic system and then buy the photovoltaic system. This strategy leads to a lower total cost than one in which the photovoltaic system is purchased as soon as the projected life-cycle cost equals the discounted value of the expected savings of conventional energy.

From a different point of view, this breakeven calculation is exactly equivalent to computing the levelized annual cost of owning and operating the photovoltaic system, but levelizing in current dollar terms (the customary procedure in the utility industry), and setting it equal to the levelized annual cost of fuel, where the fuel price is assumed to rise at exactly the rate of general inflation (i. e., to remain constant in real terms).

This approach is the same as that used in the Photovoltaic Program Multi-Year Plan (MYPP) (Ref. 9) and the economic parameters used in the analysis were, in general, the same as those adopted in the MYPP. The MYPP computations, however, only considered the case where the photovoltaic plant owner is an investor-owned utility. In order to provide coverage for the municipal utility case, appropriate values for the relevant financial parameters were defined, on the basis of the standard ERDA/EPRI levelized fixed charge methodology (Ref. 10), in such a way as to reflect the same general economic conditions as are represented by the MYPP parameters.

The results of this analysis, for the case where the photovoltaic systems begin operation in 1986, are presented in Fig. 2, where the breakeven photovoltaic plant cost is plotted as a function of average collected insolation (incident solar energy). The effects of different 1980-1986 oil price escalation rates (expressed in constant-dollar terms -- i.e., over and above general inflation) are shown, and results are presented for both privately-owned and municipal utilities. (The differences between the breakeven figures for privately-owned and municipal utilities are due primarily to the differences in the tax status of the two types of utility, to the fact that municipals pay no dividends and are entirely debt-financed, and to the effect of these factors on the effective cost of capital). The range of photovoltaic system costs that are expected if baseline technology collectors, at $0.70/W$_p$, are used is also indicated in the figure by shading.

These computations suggest that baseline-technology photovoltaic power plants may be economically competitive as early as 1986 with oil-steam generation on the basis of fuel savings alone, at least in favored locations and in municipal utilities. When one considers the conservatism built into this analysis (no capacity credit for photovoltaic systems, only 3-9% annual oil price escalation to 1986, no credit given for displacement of higher-price distillate fuels) and the likelihood that the availability of oil may be quite limited in the late 1980s, early use of baseline technology photovoltaic systems for oil conservation appears to have genuine commercial potential -- a potential, furthermore, that can only increase after 1986.

Results of essentially the same analysis, but presented in a different manner, are shown in Fig. 3, where the breakeven photovoltaic system cost is plotted as a function of first year oil cost (expressed in constant 1980 dollars). In this case the solid lines represent the results for California (Southern California desert) insolation, and the dashed lines display the results obtained when Florida (Miami) insolation data are used in the analysis. The upper and lower shaded horizontal bands indicate the ranges of system costs that are expected if baseline

- MYPP ECONOMIC ASSUMPTIONS/CALCULATION PROCEDURE (6% annual inflation, 30 year system life)
- PHOTOVOLTAIC SYSTEMS INSTALLED IN 1986
- SOUTH FACING FLAT PLATE ARRAYS TILTED AT LOCAL LATITUDE
- 1980 OIL COST $21/BARREL (1980 dollars)

REAL (constant dollar)
OIL PRICE ESCALATION
RATES, 1980-1986, %/ year

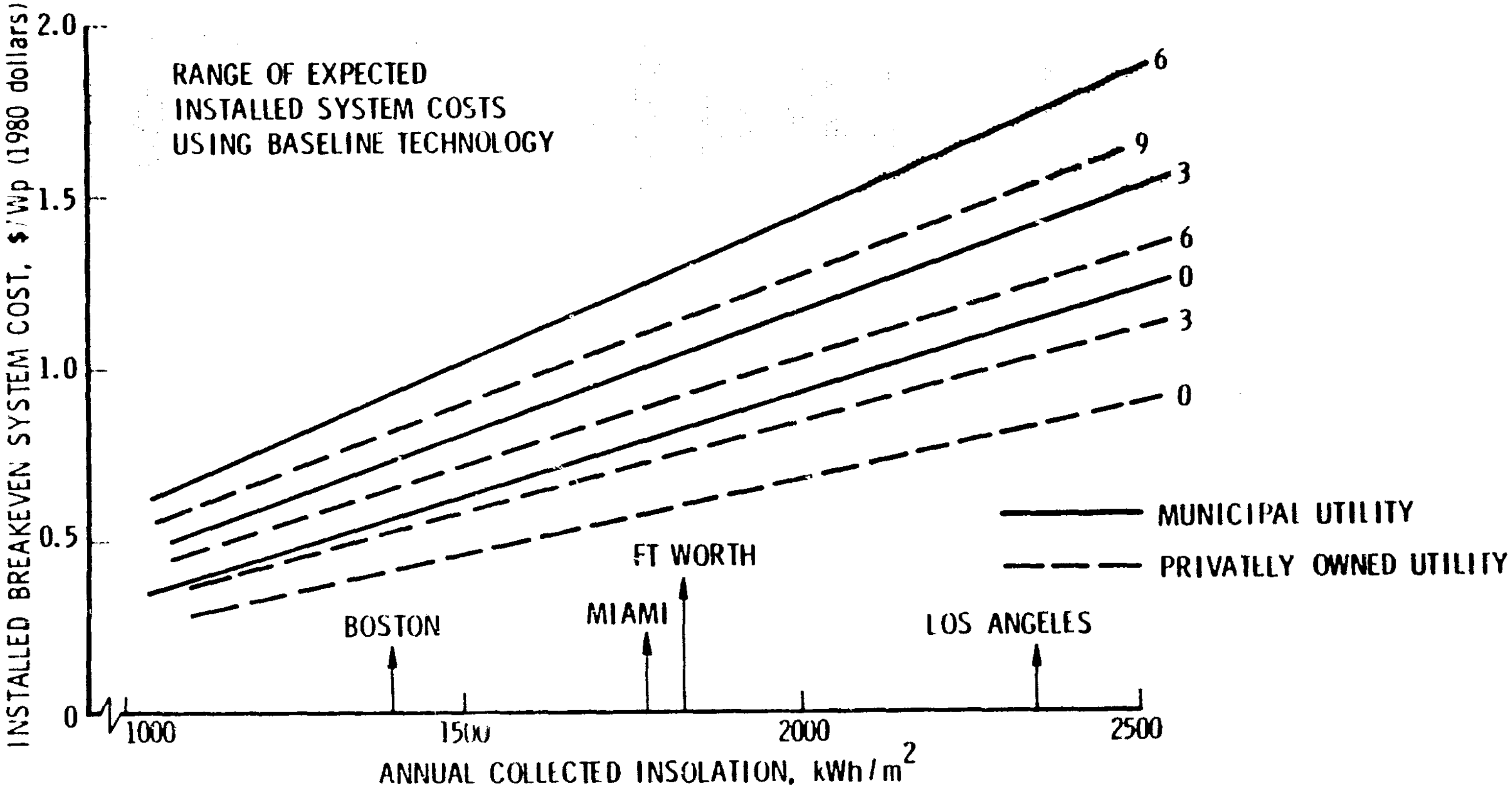


Figure 2

Breakeven Costs (Installed) for Photovoltaic Power Plants in Competition with Existing Oil-Steam Plants

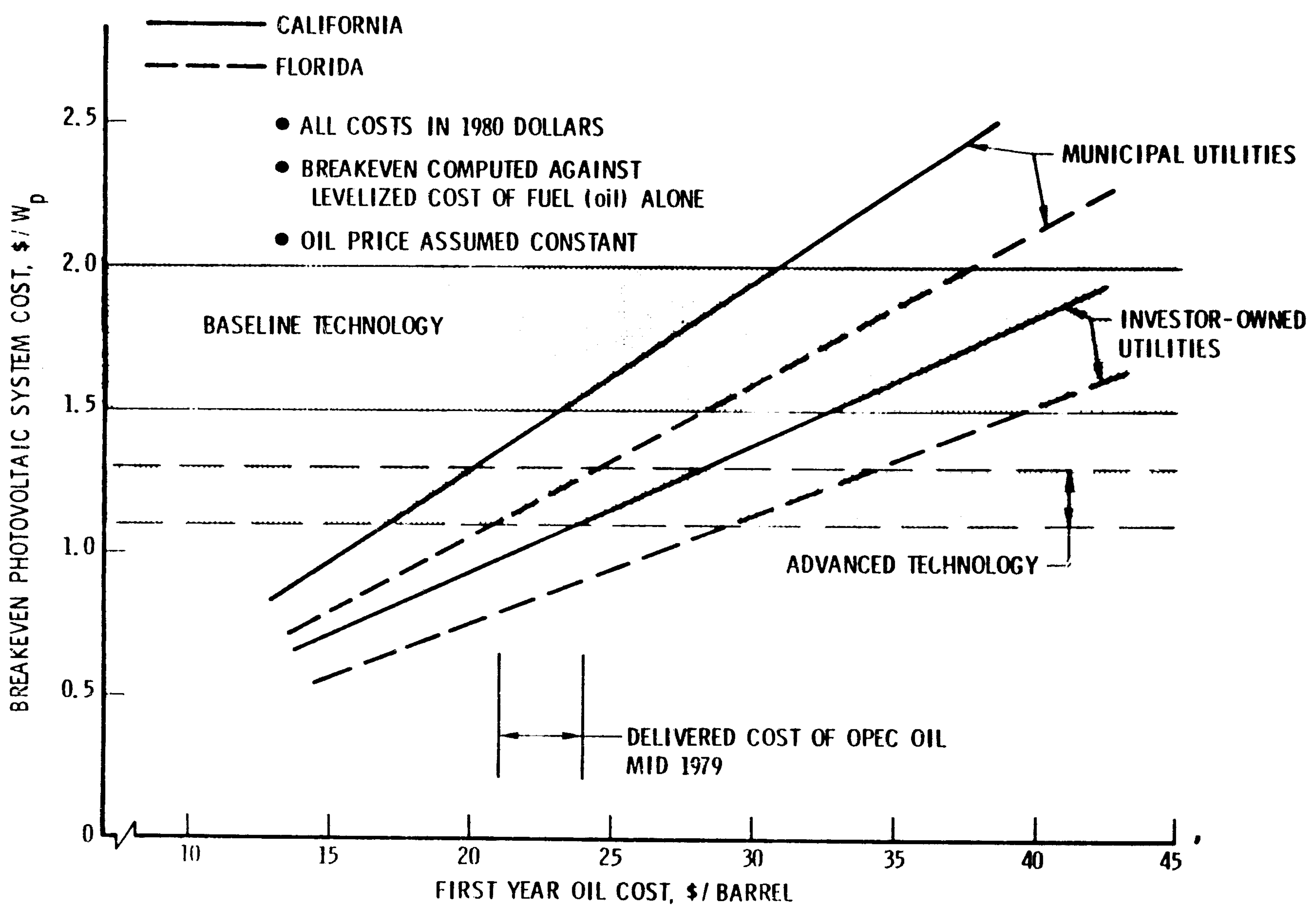


Figure 3

Breakeven Photovoltaic Power Plant Cost vs. Oil-Steam Power Generation

and advanced technology collectors, respectively, are used. The graph in Fig. 3 indicates that photovoltaic power costing \$1.50 - 2.00/W_p will be economically competitive with oil-fired power generation in California municipal utilities as soon as oil prices reach real values (in 1980 dollars) in the \$25-30/barrel range. Since OPEC oil prices are already in this range (at the close of 1979), photovoltaic central power generation might now be approaching cost-effectiveness relative to oil-fired generation if the baseline-technology goals had already been reached.

D. The Oil Conservation Market for Photovoltaic Central Power Plants

If, indeed, there is a real possibility that photovoltaic central power generation will be economically competitive with oil-fired generation, in favored locations, in the latter half of the 1980's, it is of interest to investigate the magnitude of the market that would thereby be opened up. In this section, some results of a preliminary survey of this market are presented.

Because of limitations on time and available resources, this initial survey was largely confined to the portion of the market that lies in the U. S. Sunbelt. For the purposes of the survey, the Sunbelt was defined to be Regions 4, 6, and 9 of the Utility Industry Statistical Data Regions identified by the DOE Office of Utility Project Operations. (The locations of these regions are indicated on the map shown in Fig. 4.) Data for the entire U.S., however, are included in Table 1, which lists the total oil-fired and gas-fired generation capacity in each region, as of the end of 1978 (Ref. 11). Although the focus of the survey was on oil-fired capacity, the gas-fired component is also included because, as was mentioned earlier, governmental actions to induce reductions in the consumption of natural gas for power generation are expected. In Table 1, the totals for oil-fired generation include only plants whose primary fuel is oil, although many gas-fired plants use oil as a secondary fuel. Similarly, the gas-fired totals include only plants for which gas is the primary fuel; in many cases gas is a secondary fuel for oil-fired plants.

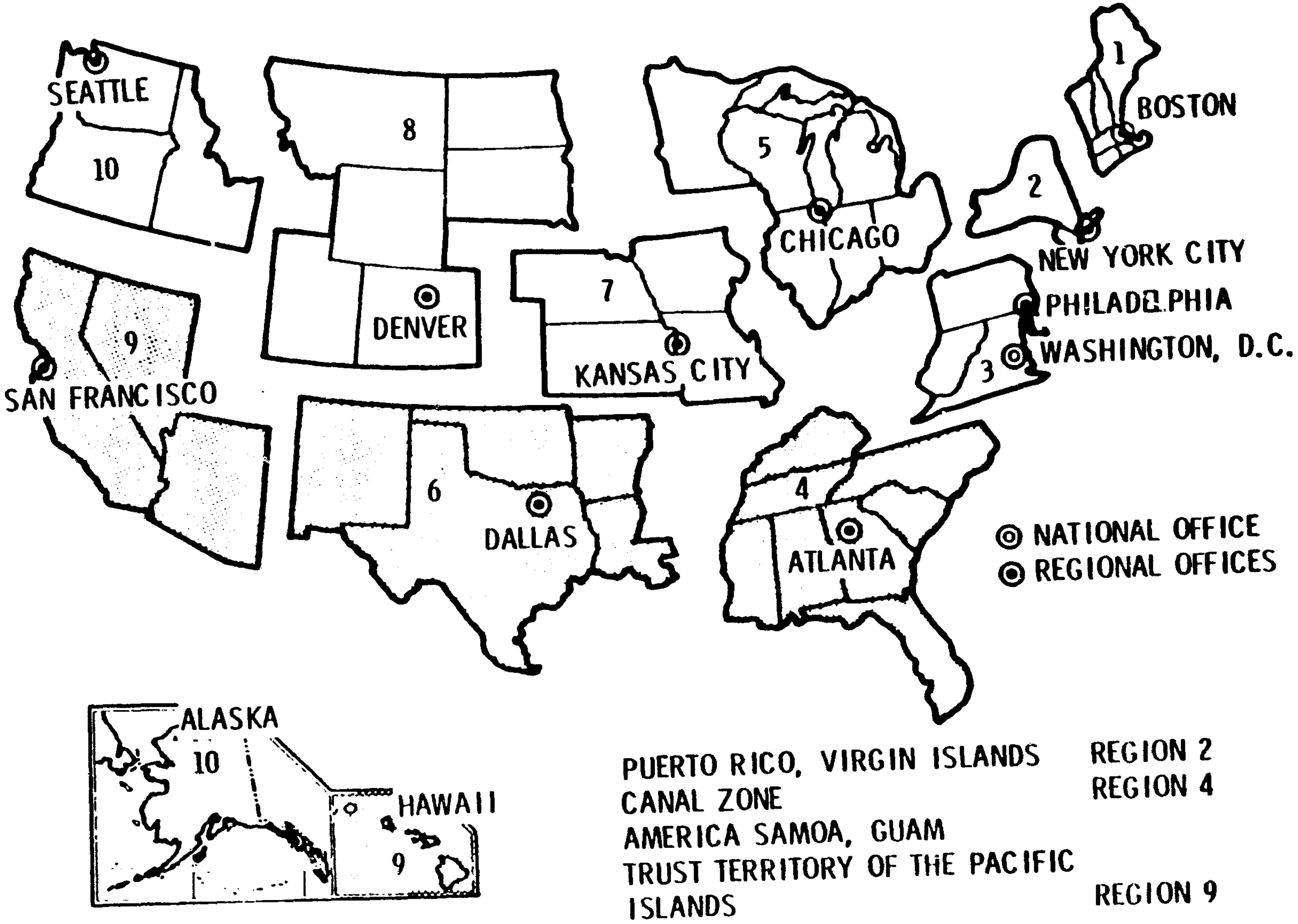


Figure 4

Utility Industry Statistical Data Regions as Defined by the DOE
Office of Utility Project Operations

Table 1 U. S. Oil-Fired and Gas-Fired Generation Capacity (MW)

Region	Oil-Fired Capacity Existing (1978)	Oil-Fired Capacity Projected	Oil-Fired Capacity Total (1999)	Gas-Fired Capacity Existing (1978)	Gas-Fired Capacity Projected	Gas-Fired Capacity Total (1979
1	13,003	369	13,372	9	0	9
2	32,040	1,220	33,260	207	0	207
3	19,463	2,032	21,495	200	0	200
4	26,560	3,119	29,679	5,521	0	5,521
5	17,465	2,578	20,043	1,562	38	1,600
6	5,981	587	6,568	59,477	0	59,477
7	3,922	1,299	5,221	5,536	55	5,591
8	1,394	83	1,477	354	0	354
9	30,064	4,014	34,078	1,478	280	1,758
10	1,443	100	1,543	540	186	735
Total Oil/Gas	151,335	15,401	166,736	74,893	559	45,452
Total U.S. Capacity	587,873	346,417	934,287	587,873	346,417	934,287
% Oil/Gas	25.7	4.4	17.8	12.7	0.2	4.9

The data from the three Sunbelt regions, highlighted in Table 1, show that tw of the three (Regions 4 and 9) have large concentrations of oil-fired capacity, and that, while the oil-fired capacity in Region 6 is relatively small, this region has a great deal of gas-fired capacity. It is also of interest to note that nearly 26% of the total U.S. generation capacity at the end of 1978 was oil-fired and that, even though relatively little new oil capacity is planned for the remainder of the century, the percentage in 1999 will still be almost 18%.

A state-by-state breakdown of the data for the three Sunbelt regions is given in Table 2. Inspection of these data reveals that three states in particular -- Florida, California, and Hawaii -- are very heavily dependent on oil. The potential market in Hawaii is especially interesting because, while Hawaii does not consume a great deal of oil in absolute terms, it is almost totally dependent on this fuel for electric power. Furthermore, substitution of coal-fired generation for the present oil-fired generation would be especially difficult for Hawaii, whose mid-ocean location intensifies the problem of bringing in such a bulky fuel as coal. In California, also, reduction of the dependence on oil by using coal faces major obstacles, raised in this case by the necessity to avoid exacerbating an already-serious air pollution problem. For three of the states -- Louisiana, Oklahoma, and Texas -- dependence on gas is so great that an attempt to reduce consumption by 50% by 1990 will be very difficult, especially if conversion to oil, the simplest alternative, is discouraged by the federal government.

The data on generation capacity in Tables 1 and 2 do not, of course, tell the whole story. Some of the oil and gas-fired capacity is associated with peaking plants, primarily combustion turbines, which are idle much of the time. A significant fraction of the steam turbine plants also have relatively low capacity factors (the ratio of the actual annual amount of electricity generated to the amount that could have been produced if the plant ran at rated capacity for all 8760 hours of the year). It is probably more informative, therefore, to investigate the amount of electric <u>energy</u> that is annually generated in these Sunbelt

Table 2. Sunbelt Oil-Fired and Gas-Fired Capacity

	Total Capacity (MW)	Oil-Fired Capacity (MW)	% Oil	Gas-Fired Capacity (MW)	% Gas
Region 4					
Alabama	18,051	148	0.8	560	3.1
Florida	27,857	19,230	69.1	220	0.8
Georgia	15,219	2,188	14.4	—	0.0
Kentucky	13,388	181	1.4	128	1.0
Mississippi	5,470	1,545	28.2	2,566	46.9
North Carolina	15,847	897	5.7	—	0.0
South Carolina	11,794	2,363	20.0	11	0.1
Tennessee	15,373	—	0.0	2,036	13.2
Region Total	122,999	26,560	21.6	5,521	4.5
Region 6					
Arkansas	5,434	2,410	44.4	537	9.9
Louisiana	12,637	1,547	12.2	10,990	87.0
New Mexico	4,410	436	9.9	1,018	23.1
Oklahoma	9,763	236	2.4	7,005	71.8
Texas	50,023	1,353	2.7	39,927	79.8
Region Total	82,267	5,982	7.3	59,477	72.3
Region 9					
Arizona	9,068	3,421	37.7	170	1.9
California	37,425	25,147	67.2	497	0.0
Hawaii	1,329	1,326	99.8	—	—
Nevada	3,646	170	4.7	811	22.2
Region Total	51,468	30,064	58.4	1,478	2.9

states by oil-fired and gas-fired plants. Table 3 contains such information, for the year 1978; the data were abstracted from the FPC Form 4 Data File. Inspection of the table shows that, on this basis, Florida, California, and Hawaii still stand out as being heavily oil-dependent, but that Mississippi and Arkansas are equally striking examples. (Apparently, in Mississippi, much of the gas-fired capacity either has low capacity factor or is frequently fired with the alternative fuel, i.e., oil.) Louisiana, Oklahoma, and Texas show up again in Table 3 as receiving all but a small fraction of their electricity from gas-fired plants.

The same basic message is conveyed by the data in Table 4, which presents figures on the 1978 consumption of oil and gas for generating electricity. The consumption data on residual oil, distillate, and diesel fuel are expressed in terms of barrels/day, while the natural gas figures represent "equivalent" barrels/day of oil, i.e., the number of barrels/day of oil that would have the same heat content (Btu) as the gas actually consumed. Florida and California again stand out as consumers of oil for generating electricity, while Texas alone burns more than half of the natural gas that is used in all three regions for this purpose.

The data in Tables 1-4 clearly demonstrate that, in at least half a dozen of the 17 states of the three Sunbelt regions, electric utilities are heavily dependent on oil or natural gas. As the prices of these fuels and the other constraints on their consumption (supply limitations, government restrictions) increase, the utilities in these states will be driven more and more toward other modes of generation. They therefore constitute a very attractive potential market for photovoltaic systems, when array prices fall to cost-competitive levels.

As was indicated in the graphs of Figs. 1 and 2, this cost-competitive situation will arise first in the municipal utilities, or in co-operatives and state or federal projects which also have access to lower-cost capital than is available to privately-owned utilities. While the municipal utilities, in particular, incorporate only a relatively small fraction of the total generation capacity in the Sunbelt (or elsewhere, for that matter), the absolute magnitude of their capacity is

Table 3 Sunbelt Oil-Fired and Gas-Fired Generation

	Total Generation (GWh)	% Oil	% Gas
Region 4			
Alabama	71,575.1	0.7	0.9
Florida	94,632.2	48.6	15.1
Georgia	55,151.0	6.2	0.8
Kentucky	55,637.6	0.2	0.2
Mississippi	19,653.9	60.6	17.9
North Carolina	65,094.1	1.5	-
South Carolina	44,462.1	8.8	1.0
Tennessee	60,458.6	3.9	-
Region Total	466,664.6	14.8	4.2
Region 6			
Arkansas	19,763.0	40.6	2.6
Louisiana	61,831.0	23.6	59.7
New Mexico	19,983.5	1.1	28.6
Oklahoma	41,290.3	0.3	86.2
Texas	194,508.8	2.1	75.3
Region Total	337,376.6	8.0	66.8
Region 9			
Arizona	30,630.0	10.0	16.4
California	141,323.9	43.0	21.1
Hawaii	6,835.1	91.3	-
Nevada	13,057.9	12.9	16.1
Region Total	191,846.9	37.4	19.3

Table 4. Oil and Gas Consumption for Electricity Generation in Sunbelt

	Fuel Consumption (Barrels/Day)			
	Residual Oil	Distillate	Diesel	Natural Gas*
Region 4				
Alabama	244	2,945	-	3,203
Florida	197,668	38,552	807	72,164
Georgia	14,612	3,512	1	2,685
Kentucky	472	185	-	551
Mississippi	54,177	934	-	19,747
North Carolina	3,582	1,771	-	2
South Carolina	15,517	2,350	-	2,367
Tennessee	-	14,182	-	-
Region Total	286,272	64,431	808	100,719
Region 6				
Arkansas	36,970	731	11	3,193
Louisiana	67,905	42	130	168,576
New Mexico	1,165	18	47	28,894
Oklahoma	374	139	90	158,736
Texas	18,470	262	199	680,675
Region Total	124,884	1,192	477	1,040,074
Region 9				
Arizona	11,254	4,133	16	24,830
California	269,805	7,243	100	137,975
Hawaii	27,032	1,008	1,115	-
Nevada	7,674	49	16	9,931
Region Total	315,765	12,433	1,247	172,736

*Equivalent barrels of oil, at 6 (10^6) Btu/barrel and 10^6 Btu/MCF

quite substantial and some of them use a lot of oil. Table 5 presents the oil-steam capacity and fuel consumption data for some of the larger municipal utilities in California and Florida. Also shown in the table are the breakeven costs for photovoltaic systems in these two states, for the year 1986 and 1990. The breakeven computations were carried out as described in Section C, on the basis of an assumed 6%/year real escalation rate (over and above general inflation) in the period between the present and the year in question (1986 or 1990).

The utilities listed in Table 5 are likely to be the initial targets for photovoltaic penetration of the utility market. The combination of falling photovoltaic system costs and rising oil prices, however, should bring rapid increases in the fraction of Sunbelt oil-steam capacity for which photovoltaic generation is a cost-effective alternative. The growth of the total market that will thereby be made accessible to photovoltaic systems operating in the oil-saving mode is illustrated by the bar-graph in Fig. 5. The heights of the bars are proportional to the total daily consumption of residual oil in those Sunbelt states where photovoltaic power is cost-competitive with the consumption of oil for power generation, for two different assumed values for the total capital cost of the photovoltaic system. It was assumed that oil prices will rise at a real rate (above general inflation) of 6%/year between the present and 1990 and at a rate of 3%/year in the years that follow, and the breakeven cost calculation was carried out as described in Section C. In the figure, no bar corresponding to the $\$1.10/W_p$ photovoltaic system cost is shown for the year 1986, because system prices are not expected to drop to that level until 1990, at the earliest.

The bars in Fig. 5 indicate that in 1986 photovoltaic systems costing $\$1.60/W_p$ will be cost competitive in municipal utilities in a few Sunbelt states (actually only in Arizona, California, New Mexico, Nevada, Texas, and Oklahoma). By 1990, however, such systems will be competitive in municipal systems throughout the Sunbelt, in federal projects in a number of states, and in privately-owned utilities in a few states (Arizona, California, and New Mexico). By 1995, the

Table 5. Major Oil-Fired Municipal Utilities in the Sunbelt

Municipality	Total Capacity MW	Oil-Steam Capacity MW	Residual Oil Consumption Barrels/day	Breakeven Photovoltaic System Cost $\$/W_p$
California				
Burbank	274	182	1,461	
Glendale	315	163	497	1.92 (1986)
Los Angeles	5,035	2,867	35,991	2.42 (1990)
Pasadena	303	236	1,487	
Florida				
Jacksonville	2,336	1,768	28,399	
Lakeland	415	353	3,545	1.58 (1986)
Orlando	782	744	9,420	1.99 (1990)
Tallahassee	515	442	4,967	

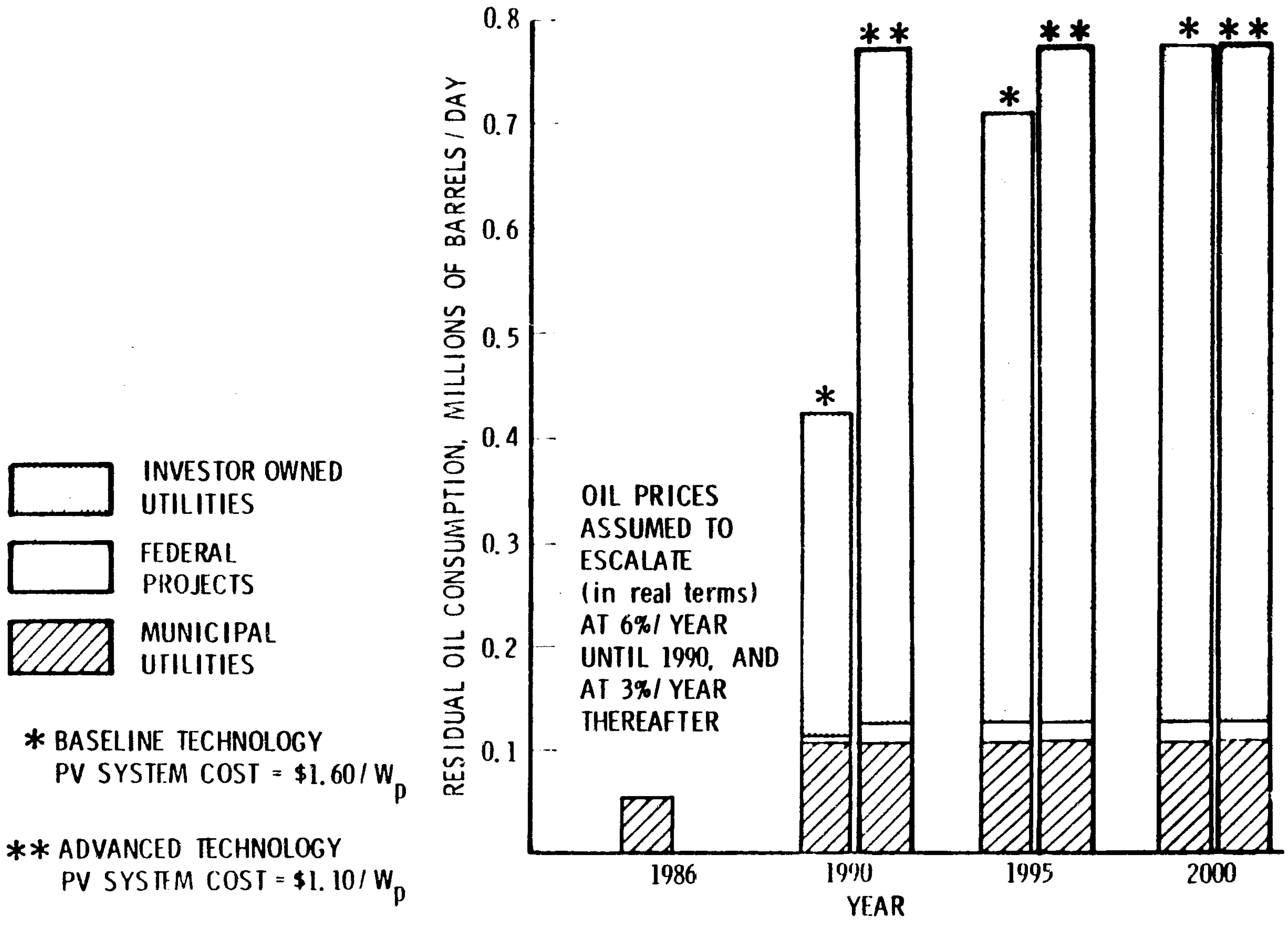


Figure 5

Residual Oil Consumption in Sunbelt Utilities Where Photovoltaic Systems are Competitive

$1.60/$W_p$ systems will be competitive in all Sunbelt municipals, in virtually all federal projects, and in privately-owned companies in most of the states. One the other hand, if systems costing $1.10/$W_p$ become available in 1990, they will be competitive in all of the Sunbelt states in all types of utilities. The total consumption of residual oil for power generation in these states is expected to be about 770,000 barrels/day, if nothing is actually done to shift the load to other types of generation capacity. This number thus represents an upper limit on the amount of oil consumption that could be displaced by photovoltaic generation in the Sunbelt.

E. Conclusions

The analysis discussed in Section C and the data presented in Section D support the following general conclusions:

1) Photovoltaic penetration of the utility central station market could become possible as early as 1986. It is expected that photovoltaic collector modules using one or more of the baseline technologies and priced at $0.70/$W_p$ will become commercially available by 1986, provided only that sufficient production volume can be achieved. It is further expected that complete photovoltaic power plants using such collectors should be buildable for a total cost in the $1.50 - 2.00/$W_p$ range. Photovoltaic power from $1.50 - 2.00/$W_p$ plants will be cost-competitive in 1986 with electricity generated by burning oil in existing plants in many municipal utilities in the U.S. Sunbelt.

2) Near-term sales of photovoltaic modules for use in central power plants could be substantial, and substantial savings of oil could be achieved. There are a number of municipal utilities in the prime Sunbelt states (California, Florida)

that are heavily dependent on oil and are under heavy pressure to reduce this dependence. There is a real possiblity that one or more of these utilities will construct a photovoltaic power plant when costs in the $1.50 - 2.00/$W_p$ range are achieved. Because of the multi-megawatt size of central power plants, construction of even one or two full-scale photovoltaic plants would represent a major purchase of photovoltaic modules. Electricity from these plants will directly displace electricity from oil-fired plants and will thus save significant quantities of oil.

It cannot, of course, be contended that the construction of photovoltaic generation capacity is the only option available to oil-dependent Sunbelt utilities that are striving to reduce their consumption of oil. At the present time, many of these utilities are looking to coal-fired generation as the most suitable alternative. In most cases this will mean the construction of complete new plants, since many of the existing oil-steam plants are not suitable for conversion in a cost-effective manner to the use of coal. Utilities choosing this option will have to contend with a variety of issues: air pollution prevention, solid waste disposal, land requirements for coal storage, availability of bulk fuel transportation, and the possibility of disruption of the fuel supply by work-stoppages in the notoriously strike-prone coal-mining industry. Increased reliance on coal-burning (or the burning of any hydrocarbon fuel, for that matter) also raises the spectre of an ultimate increase in atmospheric CO_2 concentrations to unacceptable levels.

A second option is to construct nuclear plants to serve the baseload demand and to use the existing fossil-fueled plants to serve the cycling portions of the load. In this case a different set of issues will need to be dealt with: siting problems and long construction lead times, seismic safety questions, nuclear waste disposal, security against sabotage or fuel diversion, and the possiblity of accidental release of radioactive materials into the environment.

A general program of conservation of electric energy in a utility service area would also provide a substantial amount of relief from the pressure to substitute other forms of power generation for those using oil. This relief, of course, will be temporary; conservation will only postpone the time when new non-oil generation plants must be constructed.

The availability of one or more of the non-conventional generation technologies -- photovoltaic, solar thermal, geothermal, wind -- simply adds new alternatives to the list of options available. None of these options provides an obviously superior solution to the problem. There are significant difficulties associated with each of them, and it is unlikely that any utility will choose one of them to the exclusion of the others. Instead, a strategy combining several of the options is likely to be used. It is the principal contention of this report that photovoltaic central power generation is likely to be a viable competitor for a position in this mix of options by as early as 1986 -- a date significantly earlier than had previously been considered possible.

IV. SOME UTILITY INDUSTRY COMMENTS ON CENTRAL STATION ACTIVITIES IN THE DOE PHOTOVOLTAIC PROGRAM

A. Introduction

The integration of the ongoing National Photovoltaic Program into the larger structure of the Department of Energy has required the development of a hierarchy of planning documents. The first of them, a multi-year program plan (MYPP) (Ref. 1) presenting an overall view of the entire program, was released in draft form for general review and comment in mid-1979. Discussions of specific elements of the program, in considerably greater detail, are given in a number of subsidiary documents that are in various stages of preparation. Among these is the Central Station Applications Requirements Document, which describes the rationale, strategy, and structure of the DOE program to promote the use of photovoltaic solar energy conversion in central station (utility) power plants. An initial draft of this latter document was completed in July 1979 and a revised version is currently undergoing internal DOE review.

Because the ultimate goal of the central station portion of the Photovoltaic Program is to prepare the way for the use of photovoltaic power generation in the utility industry, it is clearly desirable that the point of view of this industry with respect to the planned activities be assessed before the plan has taken on its final form. As an initial step in this direction, structured interviews were held with selected utility industry representatives in the fall of 1979 with the objective of eliciting utility industry comment about Photovoltaic Program activities that relate to the central station application. It is the purpose of this report to describe these interviews and to summarize the results. The structure of the interviews is discussed in the next section (Section IV B) while a summary of the comments received is presented in Section IV C.

B. INTERVIEW FORMAT

Probably the most efficient way of acquainting the utility participants with the planned central station activities and their rationale would have been to send them, well in advance of the scheduled meeting date, copies of the draft Central Station Applications Requirements Document. This could not be done, however, because the document (which included information on projected budgets) was still in the internal DOE review process. It was therefore appropriate to prepare a briefing, to be presented during the opening phases of the interview, that described the central station program in some detail (but without budget data). Copies of the charts that were used in the briefing were, in most cases, sent to the prospective utility participants several days before the meeting so that they could inform themselves generally about the program and formulate questions to be asked during the meeting. A set of these charts is included in this report as Appendix IV A.

In each case, the meeting began with a presentation of the briefing. Participants were encouraged to ask questions during the course of the presentation, and such questions often formed the basis of informal discussions from which valuable insights about the utility point of view emerged. The briefing was followed by a period of general discussion during which the opinions of the utility representatives on the reasonableness and completeness of the program were solicited.

C. SUMMARY OF COMMENTS

Meetings were held with three different utility companies -- Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Co. (PGE), and Florida Power and Light Co. -- and with the Electric Power Research Institute (EPRI). Of the utilities interviewed, PGE and FPL are investor-owned, while LADWP is a municipal operation.

There were, as expected, a number of common elements among the opinions expressed and comments made in these four interviews. Some of the more significant of these are listed below, under General Comments. In addition, the conversations also brought forth some interesting and provocative opinions that were not expressed (and perhaps not shared) by all of the organizations interviewed. Some of these are also listed below, under Individual Comments. (The sources of these comments are indicated by the initials of the utility company, in parentheses, at the end of each one.) More detailed summaries of the interviews are given in Appendix IV B to this report.

General Comments

The utility representatives all expressed a considerable degree of interest in the program from a technical point of view. They agreed that there is an urgent requirement for early experience with photovoltaic systems in the actual utility environment. They indicated that there is generally a positive attitude within industry management toward solar energy, in general, and photovoltaics, in particular. In part this derives from a sensitivity to trends of public opinion in this direction that, on the one hand, enhance the public relations value of a solar effort by the utility and, on the other hand, may presage pressures by state public utility commissions.

The concept of utility participation in the design and construction of the first experiments was also received positively. It was felt that, in the industry/utility design teams, the utility should be the lead organization.

The utility companies, in general, look to EPRI for guidance with respect to the more advanced technologies, with photovoltaics a prime example. They do not have sufficient staff to monitor these technologies to their own complete satisfaction and count on EPRI for support.

Although none of the utility participants specifically endorsed the view that photovoltaic power plants may be able to penetrate the oil-conservation market in the late 1980s, there appeared to be general acceptance of the concept that this market is an appropriate first target.

Individual Comments

With respect to utility participation in the design phases of the ISEE projects, it was stated that any utility would need at least three months, after first learning of the proposed solicitation, to prepare and submit a proposal. (PGE, FPL)

Several of the utilities are spending their own money -- in quantities (e.g., $5-10 million) comparable to those under consideration in the DOE Photovoltaic Program -- on experimental tests of advanced electric power generation technologies. (LADWP, PGE)

One utility expressed a complete unwillingness to enter into any contract with the federal government, largely because of the extent to which such a contract would subject the company to government direction in areas unrelated to the technical objective. (FPL)

The "linearity" of the program, the inexplicitness of decision points, and the lack of specific contingency plans were questioned, as was the appearance of a commitment to near-term commercialization without identification of the criteria that alone would make this feasible (e.g., continued high oil-price escalation and achievement of the price goals of the Photovoltaic Program). (EPRI)

The use of levelized cost figures for comparing photovoltaic and conventional power plants was also questioned. It was pointed out that this approach could conceal possible cash-flow problems that a utility could experience in the first years of operation of a system as capital-intensive as a photovoltaic plant. (It was in response to this suggestion that the cash-flow analysis reported elsewhere in this document was undertaken.) (EPRI)

APPENDIX IV A

Charts Used in Presentation of Central Station Activities of DOE Photovoltaic Program to Utility Participants

Photovoltaic Central Station Applications

Implementation Structure

THE AEROSPACE CORPORATION

Principal Obstacles to Widespread Terrestrial Use of Photovoltaic Systems

- PHOTOVOLTAIC CELL/MODULE COST (now ~ \$5-7/W_p)
- COST OF COLLECTOR STRUCTURES AND INSTALLATION
- INSUFFICIENT EVIDENCE OF LONG-TERM ARRAY RELIABILITY
- LACK OF OPERATIONAL EXPERIENCE WITH COMPLETE SYSTEMS IN USER ENVIRONMENTS

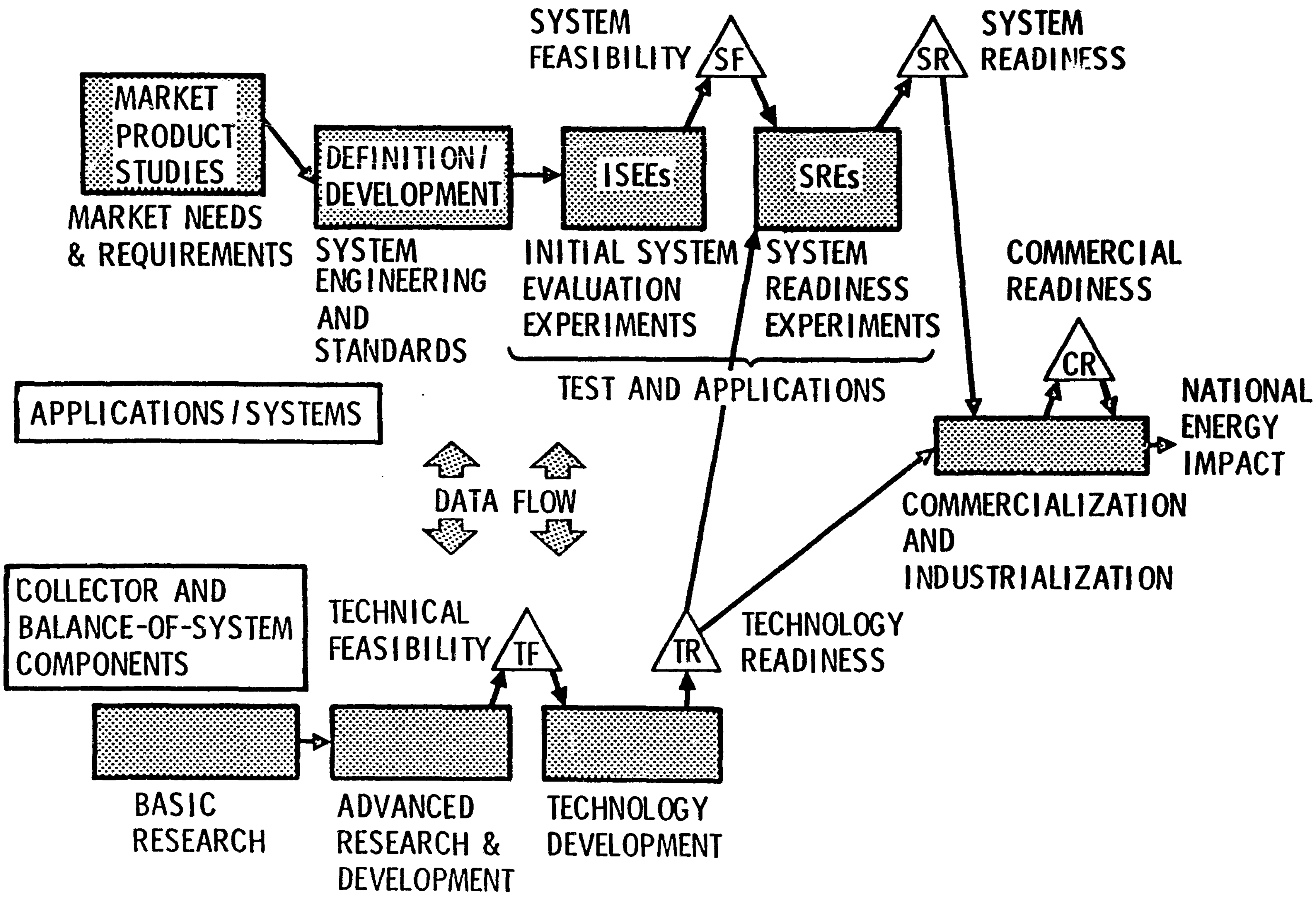
Program Objective

THE OBJECTIVE OF THE DEPARTMENT OF ENERGY (DOE) PHOTOVOLTAIC PROGRAM IS TO REDUCE SYSTEM COSTS TO A COMPETITIVE LEVEL IN BOTH DISTRIBUTED AND CENTRALIZED GRID-CONNECTED APPLICATIONS. EQUALLY IMPORTANT, THE PROGRAM WILL ALSO RESOLVE THE TECHNICAL, INSTITUTIONAL, LEGAL, ENVIRONMENTAL AND SOCIAL ISSUES INVOLVED IN FOSTERING WIDESPREAD ADOPTION OF PHOTOVOLTAIC ENERGY SYSTEMS

Program Strategy

THE PHOTOVOLTAIC PROGRAM STRATEGY IS TO ACHIEVE MAJOR SYSTEM COST REDUCTIONS TO MEET THE MARKET REQUIREMENT FOR A COMPETITIVE LIFE-CYCLE COST OF ELECTRICITY THROUGH <u>THE AGGRESSIVE PURSUIT OF ADVANCED RESEARCH AND TECHNOLOGY DEVELOPMENT.</u> IN ADDITION, <u>REAL-WORLD TESTING</u> WILL BE PURSUED <u>TO SUPPORT THE ACCELERATED TRANSFER OF THE TECHNOLOGY TO THE MARKETPLACE</u>

DOE Photovoltaics Program Strategy



Key Milestones in the Photovoltaic RD&D Process

TECHNICAL FEASIBILITY (TF) OF COMPONENTS	TECHNICAL FEASIBILITY IS REACHED FOR A PARTICULAR TECHNOLOGY WHEN: (A) STABLE AND REPRODUCIBLE PERFORMANCE CHARACTERISTICS HAVE BEEN ACHIEVED; (B) A LABORATORY-SCALE PROCESS HAS BEEN DEFINED THAT YIELDS PRODUCTS WITH CONSISTENT CHARACTERISTICS; AND (C) ANALYSIS INDICATES THAT MASS PRODUCTION IS TECHNICALLY FEASIBLE AND LIKELY TO YIELD A TECHNICALLY AND ECONOMICALLY VIABLE PRODUCT AFTER SUITABLE TECHNOLOGY DEVELOPMENT
TECHNOLOGY READINESS (TR) OF COMPONENTS	TECHNOLOGY READINESS IS ACHIEVED: (A) WITH A SUCCESSFUL SUB-SCALE DEMONSTRATION OF ALL THE INDIVIDUAL STEPS IN A PRODUCTION PROCESS THAT WOULD YIELD ECONOMICALLY COMPETITIVE AND RELIABLE PRODUCTS IF PRODUCED IN SUFFICIENT QUANTITY AND (B) WHEN PROTOTYPES ARE AVAILABLE FOR INTENSIVE PERFORMANCE AND RELIABILITY ANALYSIS
SYSTEM FEASIBILITY (SF)	SYSTEM FEASIBILITY IS ACHIEVED IN A GIVEN APPLICATION WHEN A PHOTOVOLTAIC SYSTEM CONCEPT IS FIRST CARRIED THROUGH DESIGN, INSTALLATION, AND OPERATION IN AN ACTUAL USER'S ENVIRONMENT
SYSTEM READINESS (SR)	SYSTEM READINESS IS ACCOMPLISHED WHEN FULLY INTEGRATED SYSTEMS, USING AVAILABLE TECHNOLOGY READY COMPONENTS OR PROTOTYPES THEREOF, ARE DESIGNED, BUILT, AND SUCCESSFULLY OPERATED IN AN ACTUAL USER'S ENVIRONMENT
COMMERCIAL READINESS (CR) OF COMPONENTS & SYSTEMS	COMMERCIAL READINESS IN A GIVEN APPLICATION CLASS IS ACCOMPLISHED WHEN PRODUCTS OR SYSTEMS ARE OFFERED FOR SALE AT A GIVEN PRICE

Photovoltaic Program Goals

(1980 DOLLARS)

APPLICATION	SYSTEM PRICE GOAL $\$/kW_p$	COLLECTOR PRICE GOAL $\$/kW_p$	RESULTING LEVELIZED ENERGY PRICE (Phoenix)* mills/kWh	TECHNOLOGY TYPE	TARGET DATES TR	TARGET DATES CR
RESIDENTIAL	1600	700	52**	BASELINE	1982	1986
INTERMEDIATE LOAD CENTERS	1600	700	55***	BASELINE	1982	1986
CENTRAL STATION	1100-1300	150-400	42-48****	ADVANCED	1986	1990

BASELINE TECHNOLOGY

- FLAT-PLATE SINGLE-CRYSTAL SILICON ARRAYS
- MODERATE CONCENTRATION (probably point-focus fresnel lenses or parabolic troughs) WITH SINGLE-CRYSTAL SILICON CELLS

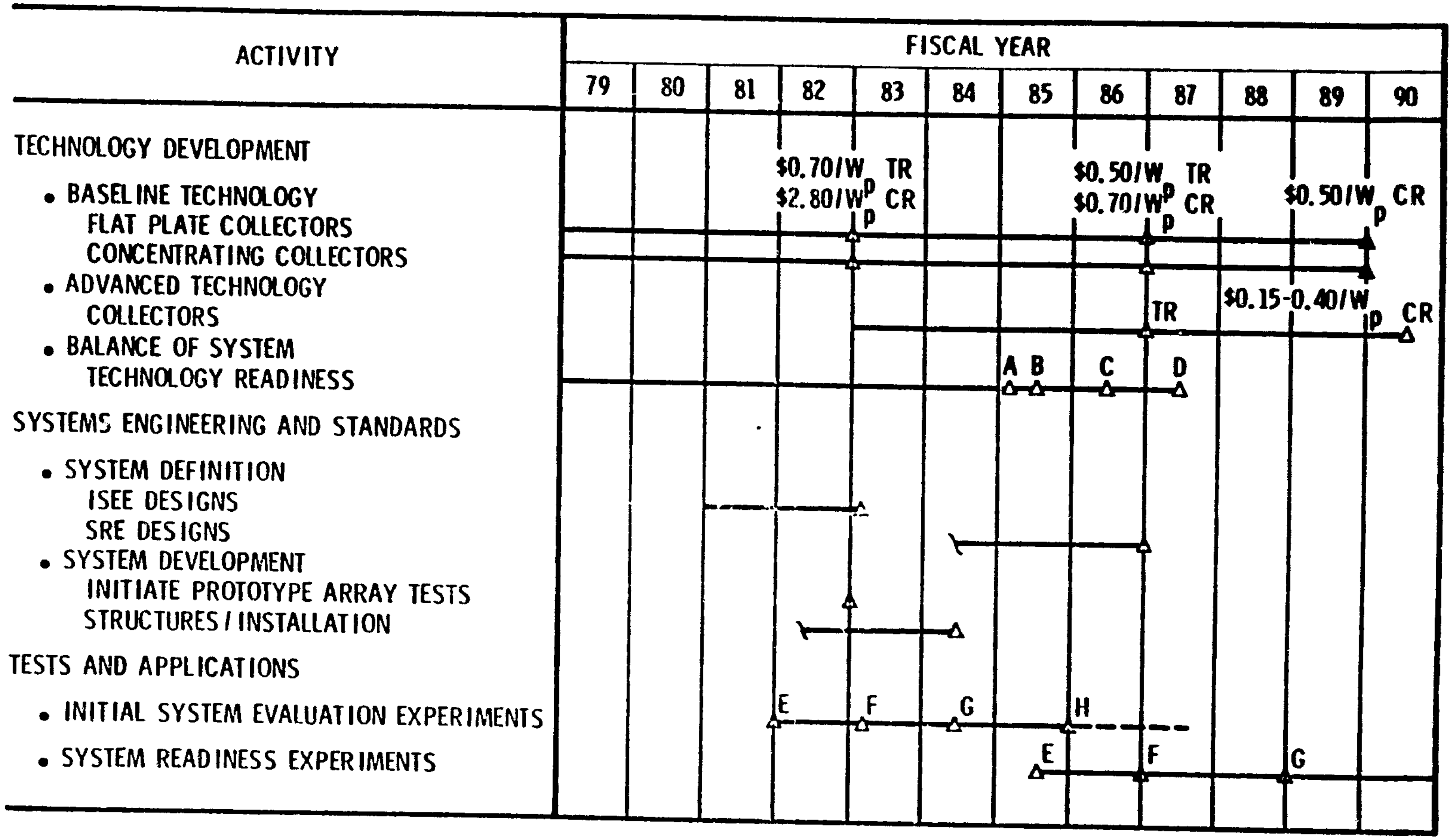
ADVANCED TECHNOLOGY

- THIN-FILM FLAT-PLATE ARRAYS
- HIGH CONCENTRATION WITH HIGH-EFFICIENCY CONVERTERS (e.g., tandem junction cells or thermophotovoltaic converters)

* Constant annual price in constant dollars (i.e., price in current dollars increases at general inflation rate)
** Effective net price to customer, with sellback to utility of excess electricity at 50% of utility rate
*** Effective net price to customer, with sellback to utility of excess electricity at 100% of utility rate
**** Busbar cost

Relevant MYPP Milestones

FOR CENTRAL STATION APPLICATIONS



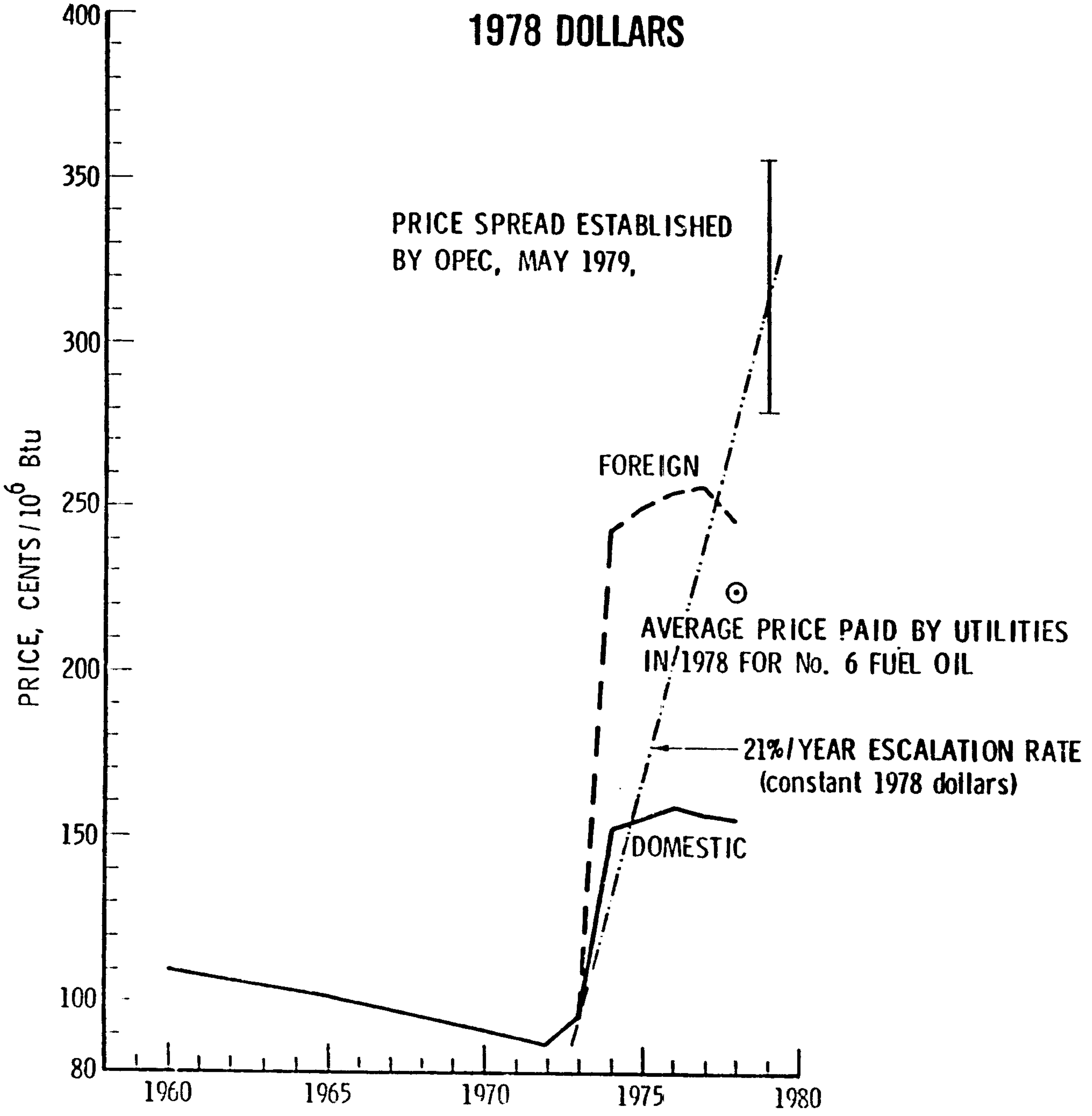
A - 5 MW POWER CONDITIONER
B - SWITCH GEAR
C - AUTOMATED INSTALLATION MACHINERY

D - NONTRACKING $\$25/m^2$ ARRAY
E - DEFINE/SELECT EXPERIMENT
F - COMPLETE DESIGN

G - COMPLETE CONSTRUCTION
H - COMPLETE INITIAL OPERATIONAL PHASE
TR - TECHNOLOGY READINESS
CR - COMMERCIAL READINESS

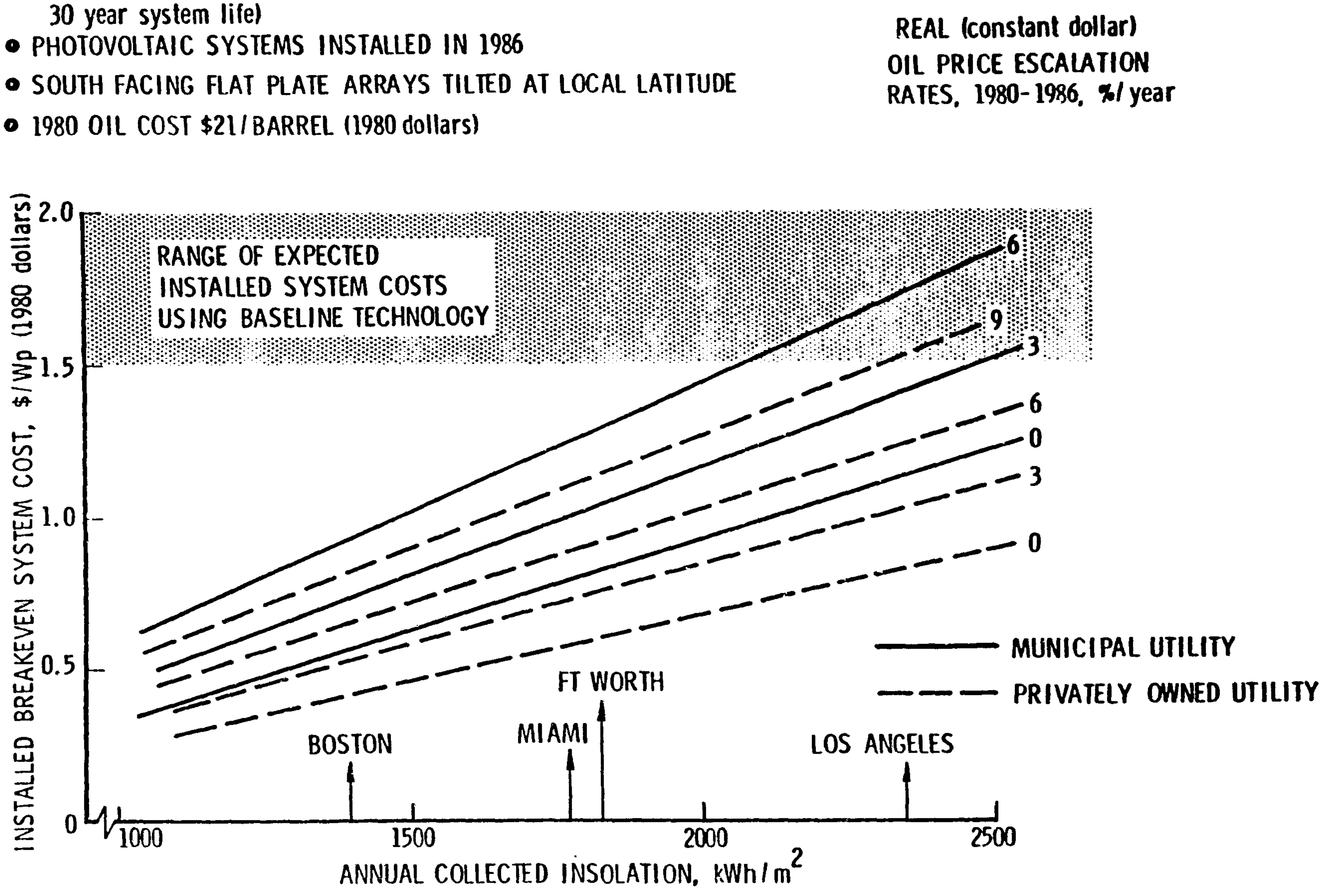
Yearly Average Crude Oil Price at Source

1978 DOLLARS



Photovoltaic Systems Oil Conservation Market

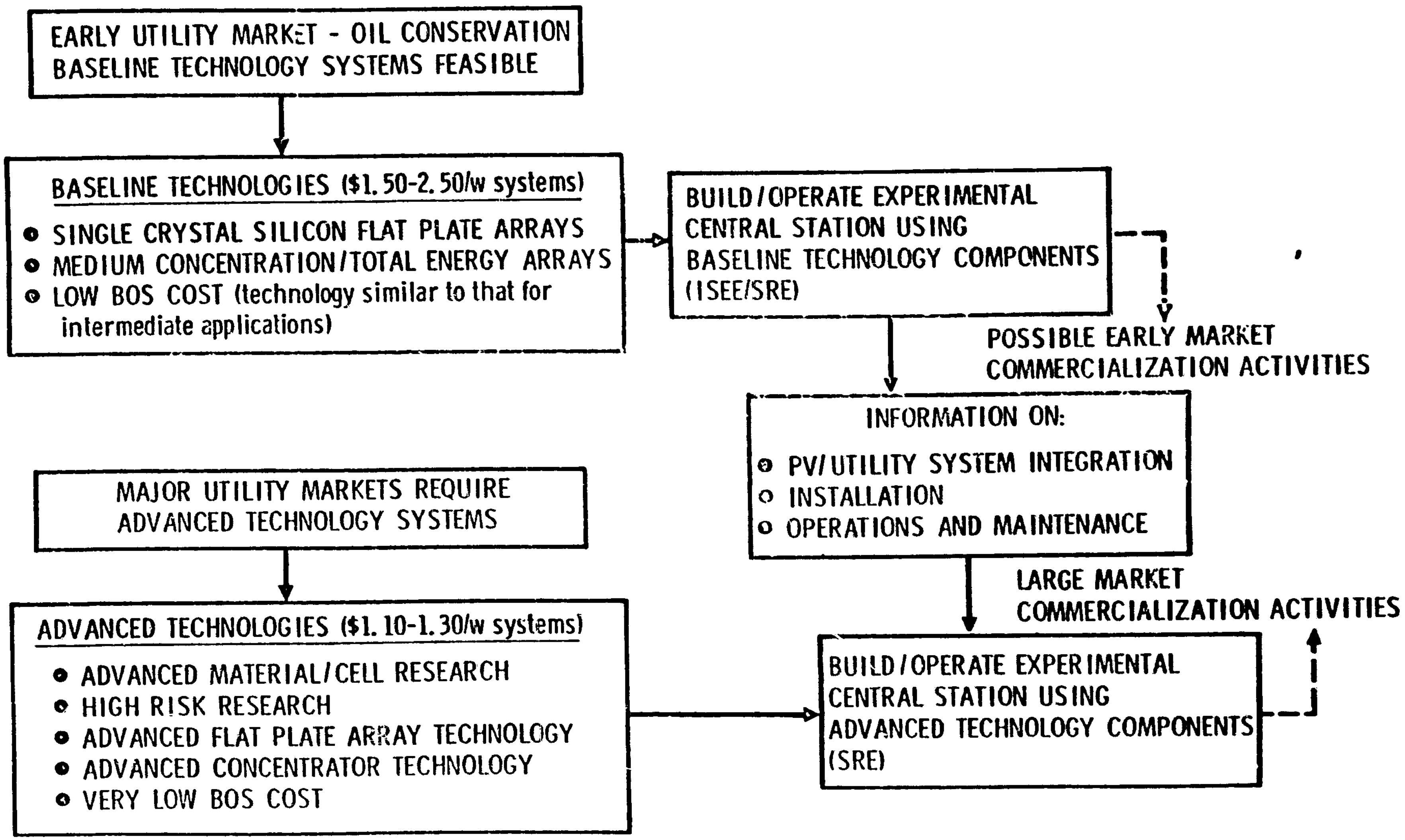
- MYPP ECONOMIC ASSUMPTIONS/CALCULATION PROCEDURE (6% annual inflation, 30 year system life)
- PHOTOVOLTAIC SYSTEMS INSTALLED IN 1986
- SOUTH FACING FLAT PLATE ARRAYS TILTED AT LOCAL LATITUDE
- 1980 OIL COST $21/BARREL (1980 dollars)



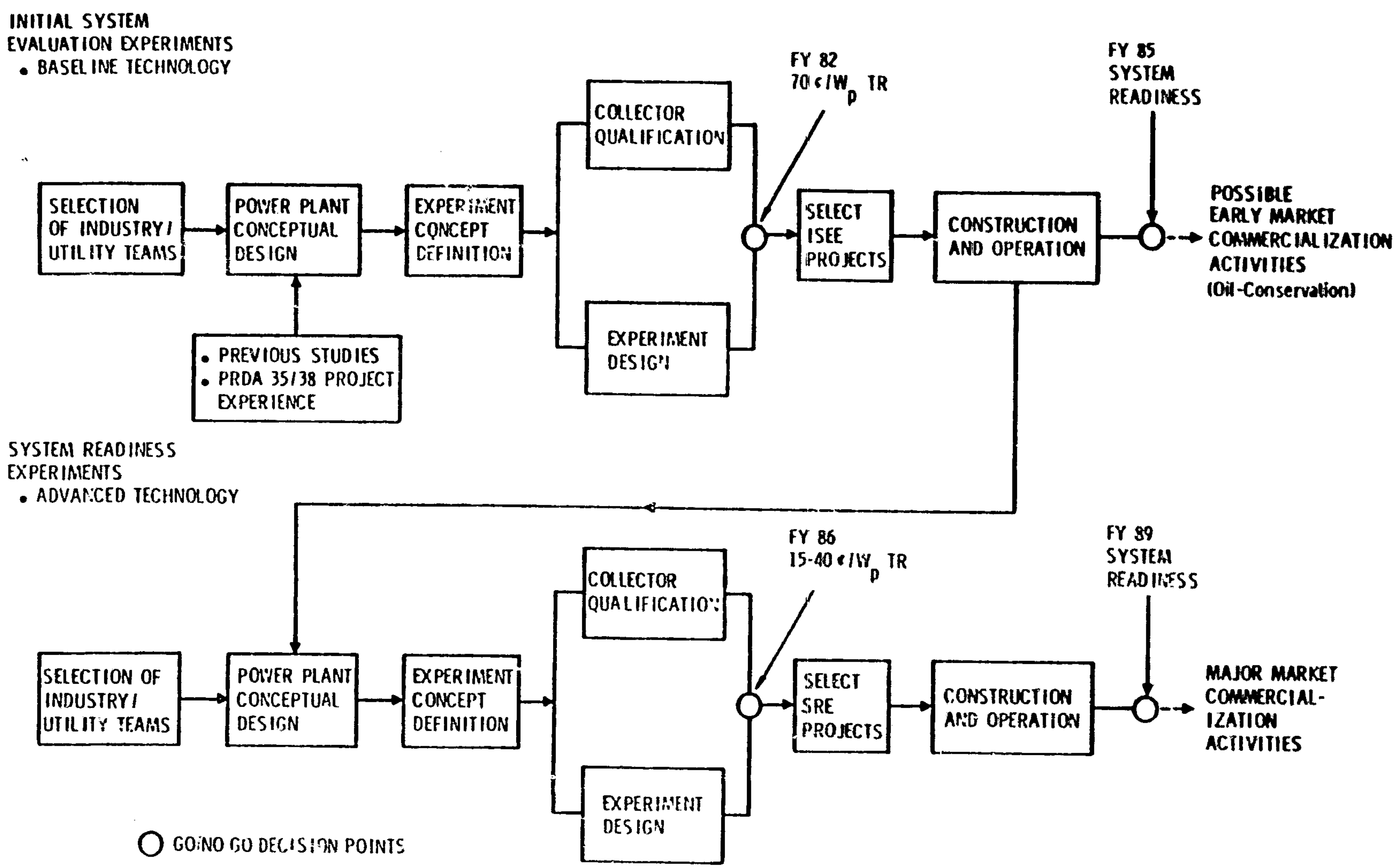
Options Available to Utilities Dependent on Oil

- MAINTAIN/EXPAND OIL-FIRED CAPACITY, PASS INCREASED FUEL COSTS TO CONSUMERS
- USE COAL
  - CONVERT EXISTING OIL-STEAM PLANTS
  - BUILD NEW COAL-FIRED PLANTS
  - CONTEND WITH RELATED ISSUES
    - AIR POLLUTION, SOLID WASTE DISPOSAL
    - LAND FOR COAL STORAGE
    - TRANSPORTATION AVAILABILITY
    - DISRUPTION OF FUEL SUPPLY BY STRIKES
    - ULTIMATE LIMIT ON ATMOSPHERIC CO_2
- ADD NUCLEAR BASELOAD CAPACITY
  - CONTINUE TO USE FOSSIL-FUELED GENERATION FOR CYCLING PORTION OF LOAD
  - CONTEND WITH RELATED ISSUES
    - SITING PROBLEMS, SEISMIC SAFETY, LONG LEAD TIMES
    - WASTE DISPOSAL
    - SECURITY AGAINST SABOTAGE, FUEL DIVERSION
    - RADIOACTIVE RELEASES
- USE PHOTOVOLTAIC OR OTHER ADVANCED-TECHNOLOGY SYSTEMS
- USE A COMBINATION OF THE OPTIONS LISTED ABOVE

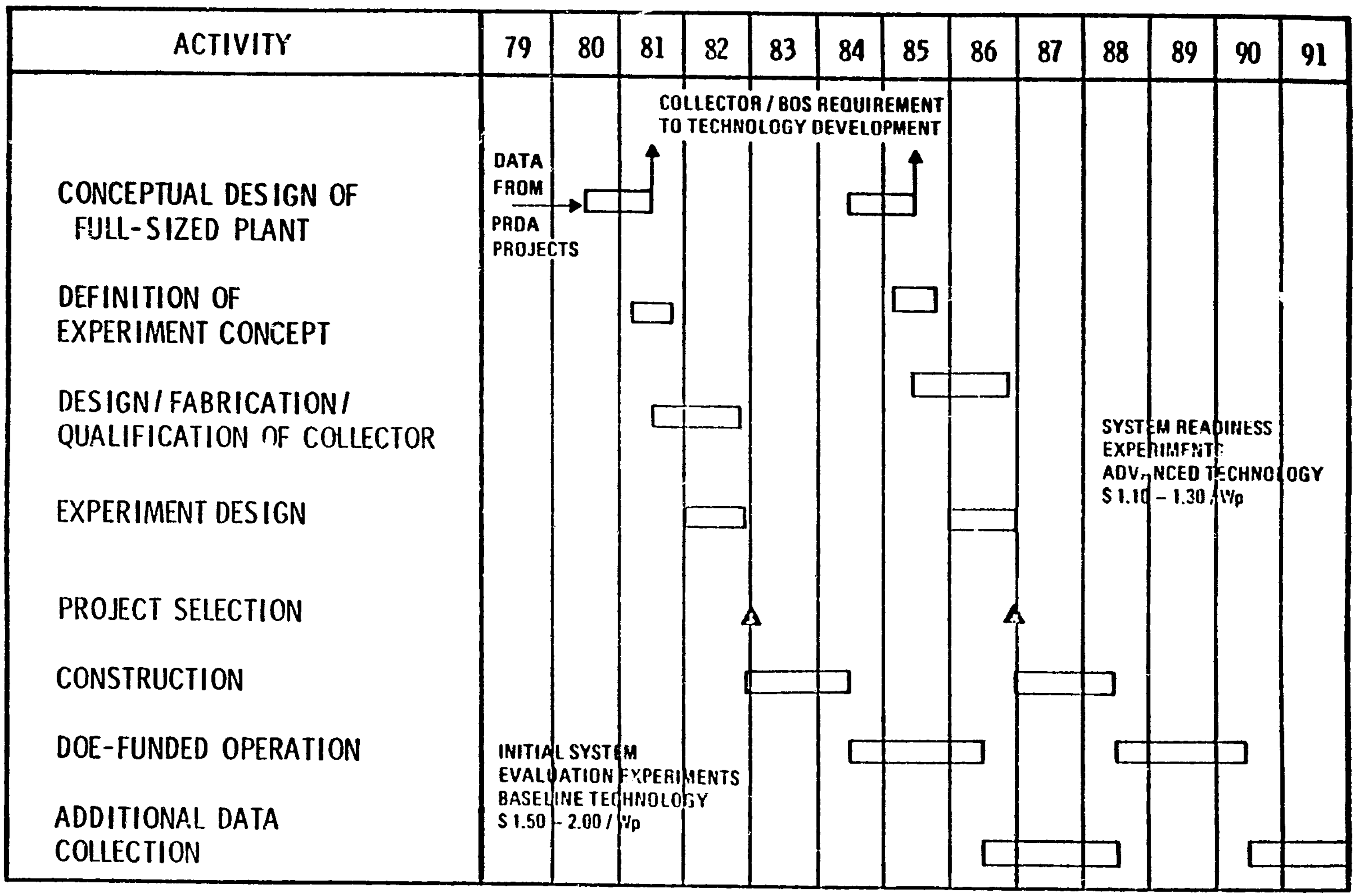
Photovoltaic Central Station Strategy



Structure of Central Station Applications Experiment Plan



Photovoltaic Central Station Experiment Plan



Utility Company Reaction

- IS THE OVERALL STRUCTURE OF THE PLAN ADEQUATE?
  - IS IT COMPLETE OR SHOULD THERE BE ADDITIONAL FEDERAL ACTIVITIES?
  - IS THE ISEE/SRE/CRDP EXPERIMENT SEQUENCE LIKELY TO ACCOMPLISH ITS PURPOSE?
  - IS THE PROPOSED INDUSTRY/UTILITY TEAM APPROACH AN APPROPRIATE WAY TO DESIGN AND CONSTRUCT EXPERIMENTS?
  - DOES THE STRATEGY OF PURSUING THE OIL CONSERVATION MARKET MAKE SENSE?
- IS THE PROPOSED SCHEDULE A REASONABLE ONE?
- WOULD YOUR COMPANY BE INTERESTED IN PARTICIPATING IN THE EXPERIMENT PROGRAM?
  - IS AN APPROPRIATE SITE AVAILABLE?
  - WHAT DEGREE OF COST SHARING WOULD BE APPROPRIATE FOR EACH TYPE OF EXPERIMENT?

Appendix IV B

Summaries of Interviews with Utility Industry Representatives

Summary of Meeting with LADWP Representatives in Los Angeles on 13 September 1979

Topic: Utility company opinions and comments on the Photovoltaic Central Station Applications Implementation Plan

Ateendees: (LADWP) - Jerry Matosec, Senior Resource Development Engineer, and Richard H. Chogyoji, Power Resources Mechanical Engineer, both in the System Development Division.
(Aerospace) - Mason Watson, Ted Davey, and Stan Leonard

After an informal presentation of a series of charts summarizing the rationale, structure, and schedule of the plan, there followed a fairly long discussion. The comments of the LADWP representatives were generally friendly toward the plan and indicated a fairly high degree of DWP interest in the renewable-resource technologies. No significant problems with the plan were identified.

Some of the principal DWP comments were:

1) (Chogyoji) The plan schedule, especially the experiment schedule, does <u>not</u> seem very ambitious.

2) Matosec several times indicated that he would like to hear EPRI's opinion of the plan. He made it clear that they (DWP) look to EPRI to provide assessments of new technologies and to keep the utility industry informed about experimental projects. He pointed out there are several levels of review within EPRI, each with utility representatives, with a top-level Advisory Committee containing utility vice presidents. Approval by the Advisory Committee of any new technology project would carry a lot of weight with the utility industry as a whole.

3) In the early stages of the discussion, Matosec expressed some doubt as to the likelihood that DWP would respond to the solicitation for industry/utility design study proposals. He noted that their PRDA-38

study had required too heavy a commitment of utility manpower. (Frank Goodman, in particular, worked some 900 hours of overtime on Phase I of that project.) As he talked, however, he shifted his position and ended by saying it was quite possible that DWP would respond to such a solicitation after all. Later in the conversation he said that the "philosophical" attractiveness of photovoltaics would lead utility company management to "bend over backwards" to cooperate if at all possible.

4) As for the concept of having industry/utility teams conduct the design studies, Matosec said that it sounded reasonable, that he sees more and more of this sort of thing coming in the utility industry.

5) One of the principal types of information utility companies would need to have before committing to PV would be data on actual O&M problems and costs and reliable long-range projections of future O&M costs. The successful operation of a 2 MW experiment might, itself, provide an adequate justification for a utility-financed experiment. Matosec cited the current DWP/SCE geothermal project that is costing DWP $10 million of its own money. In that case, Union Oil had verified the resource and made the original proposal. Utility acceptance was made easier by the fact that the familiar steam-turbine technology is involved and that a somewhat similar plant (subject, however, to very much less stringent environmental restrictions) is going in in Mexico, 100 miles to the south.

5) The current LADWP generation expansion plans involve the construction of several large baseload coal/steam plants in Utah and Nevada, in cooperation with other utility companies. Since DWP is short of capital (largely because of a charter limitation on the allowable ratio of interest payments to revenue), its participation tends to be in the form of a commitment to buy electricity, leaving capital accumulation problems to its partners. This requirement for primarily baseload capacity additions is based on the need to reduce oil consumption and the need to be able to pay back energy sent down from the northwest. Cycling and peaking requirements

will be met with the existing oil plants, some of which (the Harbor plant, in particular) were scheduled for retirement long ago. They still plan eventually to retire some of these oil plants but not until ~1995. Even then some will continue to be needed for intermediate and peaking service.

6) Asked about who one might talk to in LADWP to influence commitment of resources and, especially, people to solar projects, Matoses said that the people "up top" (the LA mayor and city councilman) would need to be persuaded.

Summary of Meeting with PG&E Representatives
in San Francisco on 20 September 1979

Topic: Utility company views, opinions, and comments on the Photovoltaic Central Station Applications Implementation Plan

Attendees: (PG&E) - Steve Hester, Energy Research Dept.; John Doyle, Senior Engineer, Alternative Energy; Clinton Ashworth, Supervising Mechanical Engineer; Kon G. Zaharoff, Electrical Engineer; and Leslie Connolly, Generation Planning Dept.
(Aerospace) - Mason Watson, Stan Leonard

The meeting was held at PG&E headquarters, 77 Beale Street, San Francisco, with the objective of acquainting the PG&E representatives with the structure of the central station plan and of eliciting their comments. It began with an informal presentation of a set of Aerospace charts, with a good deal of accompanying discussion, followed by a general discussion of the questions listed in the final chart.

The principal things we learned at this meeting were:

1) It will probably take longer than we had expected for industry/utility teams to respond to the invitation to propose to do the design studies that are the dominant FY80-82 elements of the central station plan. The PG&E representatives were generally agreed that it would take a utility company at least three months (with six months preferred) to actually get such a proposal out the door. They said, in particular, that it would probably take a month to get a decision as to whether or not to respond. If this is true, either the interval between solicitation and proposal due date will have to be increased from the six weeks we have allocated, or some method of prior notification will have to be devised.

2) Doyle and the other PG&E people expressed the view that (at least for a utility like PG&E), the industry/utility team conducting one of these studies should be led by the utility. (Watson pointed out, and the PG&E people agreed, that this might not be desirable if the utility in question were small.)

3) Most of the PG&E oil-steam capacity is fairly old (25 years or more). For these plants, conversion to coal-fired operation is not feasible.

4) PG&E management has approved the construction of a 2.5 MW wind generator, to be in operation in January 1982. The total cost, $7.5M, will be borne by PG&E.

5) PG&E feels public pressure to consider the alternative power generation technologies that are based on renewable resources and is therefore receptive to the idea of participating in experiments like those in the photovoltaic central station plan. Doyle, in particular, feels that photovoltaics and winds are the most promising of these technologies for utility applications.

6) PG&E will have 2000 MW of pumped storage (hydro) in 1983 and hopes power from the Diablo Canyon nuclear plant will be available to supply off-peak power for storage.

7) PG&E is "dabbling" in fuel cells but is not playing an active role and plans no fuel cell projects.

John Doyle joined PG&E about two months ago from Kaiser Engineering and now has responsibility within the company for evaluating advanced technologies. He is supported by an economics group that focusses on the economics of the whole utility system, with and without advanced technology generators.

Steve Hester appears to have been involved in the Varian/PG&E PRDA-35 project. He told us that it was envisioned that the project would serve as a sort of solar test site, complete with all BOS elements, at which the original concentrating collectors might later be replaced by collectors of different design. He said that when word of the project reached the local public there was a great deal of comment and many questions were asked about environmental effects and hazards.

Ashworth asked why the central station plan did not make provision for meeting some of the objectives of the SRE projects by simply installing advanced-technology collectors in one of the original ISEE projects. He assumed that the remainder of the system (other than collectors and support structures) would be essentially the same in an SRE as in an ISEE anyway.

Summary of Meeting with Personnel of Electric Power Research Institute at Palo Alto on 25 October 1979

Topic: EPRI views, opinions, and comments on the Photovoltaic Central Station Applications Implementation Plan

Attendees: (EPRI) - George Applegren, Oliver Gildersleeve, and Rene Loth, Program Integration and Evaluation; Edgar DeMeo and Frank Goodman, Jr., New Energy Resources
(Aerospace) - Mason Watson, Stan Leonard

The meeting was held at EPRI headquarters in Palo Alto and began with an informal presentation of a set of Aerospace charts, with much accompanying discussion, and concluded with a general discussion of the plan.

The EPRI representatives offered a number of fairly specific comments, criticisms, and suggestions:

1) It is not clear what would motivate many utilities to participate to a significant extent in the experiment program. It would be a good idea to ask some representative utilities (not all in the Southwest) what it would take to induce them to participate. In response to a question, the EPRI representatives said that the principal motivations offered by the plan as described were a) the acquisition of early operating experience, which would be desirable if it is at all likely that PV will be cost effective and b) the good PR aspects of participation. When asked if the recent Presidential directive to reduce oil consumption in utilities by 50% by 1990 would motivate utilities toward participating in the PV program, Gildersleeve replied, "Sure". He noted, also, that the awarding of environmental credits for installing clean power sources would also be an inducement.

2) The strategy and structure of the plan appears to be too linear, proceeding from point A to point B without acknowledgment of the contingencies that are expected to impact programmatic decisions. Not enough attention is paid to decision points and possible alternative routes to be followed if obstacles arise. This comment appears to refer more to the structure of the PV program as a whole than to the central station implementation plan (structure). It was addressed particularly to the question of what will be done if goals/milestones are not reached or are not reached on schedule.

3) One attendee (Applegren) criticized the use of levelized busbar energy costs in comparing PV electricity with oil-steam electricity. He pointed out that this procedure obscured the time dependence of the energy costs that a utility would experience during the early years of operation of a capital-intensive PV plant as a result of prescribed utility industry accounting methods. He felt that utilities might well install PV as a result of political considerations or, as a public relations gesture, in response to public opinion but that both the utilities and the public should be made aware of the true costs and of their impact in the early years. Applegren was also unhappy about the MYPP practice of levelizing in terms of constant dollars, pointing out that "nobody does it that way" (in the utility industry).

There was also general criticism of the use of a 13% fixed charge rate in the MYPP calculations. EPRI recommends a much larger FCR (18% or more) even for times when the general inflation rate is as low as 6%. DeMeo urged us to lobby DOE to use a more realistic value.

4) There appeared to be fairly general agreement that it was a good idea to attempt to get early utility participation, to bring in the utility perspective in the initial steps. Utility feedback about system design would be very desirable.

5) There was general skepticism about the likelihood that oil prices will continue to rise at anywhere near the real rates indicated in our "oil conservation breakeven" chart. In particular, real escalation

rates of 9%, or even 6%, were viewed as very unlikely. One participant (Gildersleeve) said he felt that it was a good idea to identify a fairly well defined initial-market target (i.e., the oil-conservation market). Others (DeMeo, in particular), however, said that the plan may well be promising (or appearing to promise) too much by identifying this early market. In particular, the reference to "early market commercialization", in the charts on central station strategy and plan structure, implied a much greater confidence in the actual materialization of factors leading to this market than is justified. (It will become real _if_ oil prices continue to rise very rapidly, if PV price goals are achieved, and _if_ there are not any better alternative energy sources than PV.)

DeMeo also pointed out that the construction of early ISEE's could be fully justified by the need for early real-life experience with PV central station systems. Their presence in the plan does not depend on the oil-conservation market rationale.

6) There was a considerable amount of discussion about the appropriate size for a central station experiment. The EPRI representatives appeared to feel that it might well be better to field several smaller (say 500 kW) experiments than a single larger (2 MW) one. They pointed out that in either case the actual impact on the utility (esp. on dispatch of the remaining capacity) would be negligible. Two ways of studying such impacts were suggested a) a fairly large experiment in a very small, isolated utility or b) use of a utility operation simulator (computer program) with an amplified representation of the actual performance of a small PV experiment. It was suggested that these considerations should be reflected in the plan.

7) The point was also made that it is important to locate central station experiments in several different geographic regions, rather than only in the Southwest.

Summary of Meeting with Representatives of Florida Power and Light Co. in Miami on 8 November 1979

Topic: Utility company views, opinions, and comments on the Photovoltaic Central Station Applications Requirements Document

Attendees: (FPL) - Gary Michel; Reid Culverson, Chief Engineer; W. Nola, Ass't. Chief Engineer
(Aerospace) - Stanley Leonard, Dick Fling

The meeting was held in the Florida Power and Light executive office building, at 9250 W. Flagler St., Miami. (The mail address is P. O. Box 529100, Miami 33152.) Our objectives was to describe the strategy and structure of the experimental activities discussed in the Central Station Applications Requirements Document and to elicit FPL comments. We began with an informal discussion of the set of Aerospace charts that had been prepared for use at the meeting. (Copies of these charts had been sent to Gary Michel several days before.) This was followed by a general discussion of the experiments and of the whole DOE Photovoltaic Program.

The dominant message that we received from all of the FPL representatives was very simple: this utility company is totally unwilling, at least at the present time, to accept any contract with the federal government. We were told that it is "corporate contract policy" not to enter into government contracts and that it would take a directive from the company president or its board of directors to change this policy. The engineers we were talking to, furthermore, said that, although they found the possibility of participating in a photovoltaic experiment to be technically very attractive, they would not recommend that the company change its contract policy.

We attempted to explore the reasons for this strong opposition to dealing with the government but were only partially successful. A number of specific difficulties were mentioned: too much red tape, auditing

requirements that would force FPL to change the way it keeps its books and to hire additional people to do it, various unspecified "legal issues", government regulations about hiring (equal opportunity rules, apparently). When we tried to pursue any of these topics further, in an attempt to identify some contractual management that would be acceptable, we were told that the objections were far more comprehensive than the specific examples that had been mentioned and that, therefore, the government would have to change its whole way of doing business before such contracts would be attractive to FPL. The contract objectives would have to be simple, "just engineering", without the inclusion of the many social objectives that now contaminate the relationship. When we pointed out that many of the social requirements they mentioned are already being imposed on them even in the absence of any government contracts, they replied that the acceptance of the contract would give the government additional leverage. (Toward the end of the interview, Mr. Culverson assured us that the FPL equal opportunity record was a very good one and that they fully supported such programs. It was just that they didn't want government control.)

It was also brought out in the course of the conversation that FPL has conducted research projects under EPRI sponsorship and has found the contractual relationship to be fully acceptable to corporate management. It seems likely, therefore, that if a way could be found to funnel DOE support through EPRI, FPL (and other utilities with similar views) might be induced to participate in the Photovoltaic Program.

In addition, to these discussions of the objections to dealing with the government, two other useful comments were made:

1) The time required for a utility to get its act together and prepare a proposal to conduct one of the design studies included in the central station plan would be fairly long -- at least nine months. This period would include the time needed to convince management of the desirability of responding to the solicitation. (The FPL people agreed that some of this activity could take place prior to issuance of the solicitation if credible advance notice of the solicitation were received.)

2) Mr. Nola said that FPL would be pretty leery of connecting a full size PV power plant (100 MW) to their grid unless it had been shown to be compatible by prior experience with a similar full-size plant. It turned out that the principal concern was with the harmonic content of the power conditioner unit (PCU) output and Mr. Nola agreed that if the PCU met some rigid specifications (e.g. less than 1% harmonic content) then the results of smaller scale tests might be considered adequate evidence of PV compatibility. In this connection, Gary Michel reported a conversation with a Delta Electronics engineer who has worked on the Mt. Laguna project. Apparently they have found that even a fairly small change in PV output (as a result of small clouds for example) causes the diesel generator to really jangle, with frequency swings as high as 2 Hz.

No other substantive comments were made; apparently none of the attendees except Michel had looked at the advance copies of the charts prior to the meeting. We invited them to pass along to us (by phone or mail) any additional comments they might come up with after thinking over what we had told them.

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ADDENDUM I

COMPARATIVE CASH-FLOW ANALYSES OF OIL-STEAM AND PHOTOVOLTAIC PLANTS

A. Introduction

The analyses described in Section III of this report have indicated that photovoltaic central station (utility) power plants will be economically competitive with oil-steam plants in the U. S. Sunbelt by the late 1980s, provided only that a) oil prices continue to rise at a real escalation rate (i.e., in addition to general inflation) of 3%/year or more and b) the total cost of a photovoltaic power plant can be brought into the \$1.50 - 2.00/W_p range. These analyses, however, were based on comparisons of a single economic parameter, the levelized busbar cost of electricity. Although the comparative evaluations were based on quite a conservative premise (comparing the busbar cost of electricity from a newly constructed photovoltaic plant with the corresponding cost of electricity from a fully-amortized oil plant -- with, therefore, no allowance for any capacity displacement), they still suffer from the fact that the entire economic behavior of each type of plant is compressed into a single number. This process makes it impossible to assess the way the competitive position of photovoltaic power varies over the life of the plant, and in particular, it tends to conceal the great differences that exist between the way in which cash flows vary with time in photovoltaic and oil-steam plants. Since the decision as to whether or not to build a photovoltaic plant could be influenced by perceived cash-flow problems, it is desirable to supplement the levelized-busbar-cost comparisons with a more detailed examination of all of the cash flows that arise in the operation of the two types of plant and of the way these flows vary with time.

It is the purpose of this Addendum to report the results of a preliminary comparative investigation of the cash flows arising from the construction and operation of a) a Sunbelt photovoltaic power plant and

b) a new oil-steam plant in the same location. The tool that was used in this study is a computer program, Financial Analysis Modelling System (FAMS), that computes a set of yearly balance sheets that summarize the financial status of a project, on a year-by-year basis, from the start of construction to final shut-down. It also computes several different figures of merit. One of these is the annualized cost of service, from which a value for the levelized busbar cost of electricity is readily derived, thereby permitting a comparison of FAMS results with results obtained by the levelized fixed-charge approach used in the earlier comparisons (Ref. A-1).

A description of FAMS is given in the next section of this Addendum, Section B. This is followed, in Section C, by a discussion of the input data used in the computations and a summary of the results obtained. The final section, Section D, contains a brief discussion of these results.

B. Financial Analysis Modelling System

1. Introduction

The Aerospace Corporation Financial Analysis Modelling System (FAMS) computes, as a function of time, the cost to the user (i.e., the purchaser of the electricity) of an investment in a utility project; it also computes various figures of merit for the project. The computation of the annual (or periodic) cost to the user assumes that the regulator allows the utility to recover all expenses (in the strict accounting sense) in the year in which they are incurred, including the return required to satisfy equity investors. FAMS develops the annual project expenses as part of the computation of a complete set of annual financial statements in external-reporting format for the project during both the construction and commercial operation periods. The above approach to rate determination is consistent with industry practice regarding use of the same accounting treatment for rate setting and external reports (cf. Business Week, April 3, 1978, p. 88).

2. Income Statement--Commercial Operation

The computation of the financial statements during commercial operation begins with the rate base for the first year, which is the construction cost of the project (including taxes, non-plant outlays, and returns to investors accrued or expended during construction) computed in connection with the development of the construction-phase financial statements. The first year's Income Statement is built up from the Net Operating Income (NOI) necessary to cover investors' required returns. This NOI is computed as the rate base multiplied by the allowed rate of return. The allowed rate of return is normally computed as the weighted average of the interest rate on the bonds and the allowed rate of return on equity (ROE), with the weights respectively equal to the percent of debt and equity in total capital (i.e., debt plus equity). An optional alternative procedure, also available in the model is to set the allowed rate of return on rate base *ab initio* along with the bond interest rate, and allow the rate of return on equity to be a computed quantity. (It is this option that was selected for use in the computations reported in this document.) Provision is also made for adjusting investors' rates of return for inflation each year.

The portion of the Income Statement above NOI includes Investment Tax Credit (ITC), Provision for Income Taxes (state and federal), Property Taxes, Depreciation, Insurance, Operating and Maintenance Expense, Fuel Expense, and finally, Operating Revenue. The ITC is calculated as the investment tax credit rate times the plant construction cost. FAMS assumes that the utility system has enough income to use the entire ITC tax benefit in the year of occurrence. This approach treats the project as an incremental investment in an on-going utility system. Operating Revenue is treated as if it were the cost of service, although transmission and distribution costs are not explicitly included in the analysis of the project. NOI is then the sum of Operating Revenue and Investment Tax Credit minus all of the expense items.

The Provision for Income Taxes in both utility and non-utility accounting is computed as the tax rate multiplied by taxable income. In non-utility financial modelling, taxable income is simply net operating

revenues less deductible operating expenses: depreciation, interest, and pertinent taxes. In utility financial modelling taxable income must be deduced from NOI and it is different for computing state and federal income tax, since state income tax is deductible for the federal tax computation. The formulas for computing the Provisions for State and Federal Income Taxes were obtained from some algebraic manipulation involving NOI, Interest Expense, and the federal and state tax rates. As with any business, utility companies are entitled to use accelerated depreciation schedules for computing income taxes. FAMS handles this situation by computing Provision for Income Taxes on the basis of straight-line book depreciation over the full service life of the plant (i.e., an equal fraction of the Plant-in-Service -- the first year's rate base -- is expensed each year) and then separately calculating the annual tax deferral that results from the difference between book depreciation and accelerated tax depreciation. The Deferred Tax allocations are included in the Sources and Uses of Funds, Commercial Operation, Statement and in the Balance Sheet. These schedules are discussed in the next two sections, Sections B.3 and B.4.

Property Taxes are computed as a percentage of the net book value of the project (excluding amortized taxes, non-construction costs, and returns to investors during construction). The Depreciation Expense appearing on the Income Statement is computed by the "straight-line" method, as discussed above. Provision is made for adjusting depreciation each year to replacement value. Operating-and-Maintenance and Fuel Expenses are proportional to the annual energy generated. Insurance Expense is a percent of the construction cost of the plant (excluding taxes, non-building costs, and returns to investors during construction). Operating Revenue, then is obtained as the sum of the expense items and NOI. (These expenses and return to investors are also presented in a separate cost-of-service statement, in mills per kilowatt-hour.)

Following NOI on the Income Statement, there appears Interest Expense and Other Income. These items are subtracted from NOI to obtain Net Income (NI). Other Income derives from the cumulative investment in prior years of

cash flow from the project in the utility system at the allowed rate of return; this use of the cash flow is one of several options, as discussed in Section B.5, below.

3. Sources-Uses-of-Funds Statements--Commercial Operation

Net Income is the first item on the annual Sources-Uses-of-Funds Statement. Other sources include (book) Depreciation, Change in Deferred Taxes, New Debt from Sale of Bonds, and New Equity from Sale of Stock. Uses of funds each year are Increase in Net Working Capital, Investment in Utility System, Investment in Plant and Equipment, Retirement of Debt Principal, and Dividends.

Some of the income tax provided for on the income statement may not be paid because the depreciation expense allowed for the purpose of computing the tax liability (i.e., accelerated depreciation) exceeds that used for the purpose of reporting earnings. Over the life of the project, depreciation must equal original cost (assuming no inflation adjustment), so taxes deferred on the project in early years are paid in later years when tax depreciation is less than book depreciation. Thus, no deferred tax remains at the end of the project's life. (This is not necessarily true for a utility system as a whole, however. A growing utility could conceivably defer some income taxes indefinitely.) Some of both state and federal income taxes are deferred when tax depreciation exceeds book depreciation. Since state income taxes are deductable for the purpose of computing federal income tax, the federal tax deferral is smaller than if this were not the case. The change in deferred federal tax equals the tax rate times the quantity: tax depreciation less book depreciation, adjusted for the change in deferred state tax.

4. Balance Sheet--Commercial Operation

Total Assets on the Balance Sheet consist of Net Working Capital, Investment in Utility System, and Net Plant-in-Service (equals Gross Plant-in-Service less Accumulated Depreciation). Net Working Capital may be

further analyzed into components for Fuel Stock, Materials and Supplies, and Other Net Working Capital. Total Liabilities are Deferred Federal and State Income Taxes and Long Term Debt. Equity consists of Retained Earnings and Proceeds from Sale of Common Stock.

5. Reinvestment Policy--Commercial Operation

Some method must be chosen for applying funds obtained from net income, depreciation and change of deferred taxes. These funds can be applied to payment of dividends, investment in replacement or new plant or equipment for the project, investment in some other earning asset, or retirement of debt. In FAMS, a portion of these funds is always allocated to the (straight-line) retirement of the debt on the project, while the remainder can be allocated in accordance with one of two available options. In the first of these, all of the net cash flow in excess of the debt retirement allocation is returned to the equity stockholders as "dividends". Part of this amount is treated in the program as true dividends -- return on equity --and the remainder is treated as a return of capital, i. e., a reduction of equity. It is this first option that was selected for use in the computations discussed in this report.

The second option is one in which all or part of the net cash flow, less dividends and debt retirement, is invested in a quasi-security called Investment in Utility System which earns at the allowed rate of return. Earnings from this investment are then included in Other Income on the same basis as NOI.

6. Plant Construction Costs

Plant construction costs may be modelled in three ways in FAMS. The total cost can be allocated to the years of the construction period according to the percent incurred each year. Cost amounts may be specified each year in the second method. The third method enters costs by cost category over the specific period of expenditure for each category. Total plant construction cost each year during construction is then built up from

the individual cost elements. Costs are entered in dollars of a base year (e.g., 1980) and then inflated, at a rate that may be specified separately for each cost category, to the year of its occurrence. This method of inflating costs also applies to costs incurred during commercial operation.

7. Sources-Uses-of-Funds-During Construction

Other Uses of Funds during Construction are Interest, Property Taxes, Materials and Supplies and Working Capital. No provision is made for underwriting costs, although these could easily be included. Sources of Funds During Construction are sales of bonds and common stock. These sources are allocated each year according to the target debt-equity ratio. Net cash flow from operations is zero each year during construction but it has two non-zero components which exactly offset each other. Although interest is paid to bondholders during construction, allowed dividends are accrued. This allowance for dividends is a non-cash credit which is therefore subtracted from Net Income each year to obtain net cash flow from operations. Thus there is positive net income recorded each year equal to the allowed dividends, but there is no operating income during construction. An "Other Income" item equal to the sum of interest and allowed dividends each year is recorded on the income statement. After interest is deducted, net income remains. Since no dividends are paid during construction, net income each year equals the change in retained earnings, which equals the dividend allowance.

8. First-Year's Rate Base

The value of the "Plant-in-Service" at the end of the construction period, which is the rate base for the first year of commercial operation, is computed as the sum of outlays for plant and equipment, interest expense, allowance for dividends, and property taxes during construction, less any non-depreciable cost components. During commercial operation, the allowance for dividends is amortizied on a straight-line basis and added back to

income (having been subtracted as part of book depreciation) to obtain taxable income. This is because dividends are not a deductible expense, but the allowance for dividends during construction is treated as an allowable part of the rate base.

9. Figures of Merit

FAMS computes the following measures of the project's merit: internal rate of return on total investment (IRROI); internal rate of return on equity (IRROE); present value of cash flows (PVDCF) discounted at the after-tax weighted-average cost of capital (ATWCC); present value of cost of service discounted at the user's discount rate (PVCS); levelized cost of service (LCS); and capital recovery factor (CRF).

In the IRROI and PVDCF calculations, annual cash flows are dividends, interest, stock repurchase (if any), and debt retirement (if any). At the end of the project's lifetime, assets are assumed to be liquidated at net book value so that the net cash flow in the last year includes dividends, interest, and total capital. The figures of merit are computed as of the beginning of the first year of commercial operation. Accordingly, the capital outlays during construction are accumulated at the IRROI rate to the beginning of commercial operation in the IRROI calculation. The IRROE calculation parallels that for IRROI, with dividends and repurchases as the annual cash flows and equity alone replacing total capital in the equation.

The "levelized" cost of service is the constant annual service cost whose discounted value (at the user's discount rate) equals the PVCS. The capital recovery factor multiplied by the initial investment yields a value which, if earned each year, would have a present value (discounted at the ATWCC) equal to the value of investment outlays at the beginning of commercial operation. The ATWCC is equal to the rate of return on equity times the equity-to-total capital ratio plus the quantity: (one minus the tax rate) multiplied by the interest rate and the debt-to-total capital ratio.

C. Computations

For the purposes of this study, FAMS was used in an analysis of the time-varying financial status of four representative power plants: two photovoltaic plants, one constructed by an investor-owned utility company and one by a municipal utility, and two new oil-steam plants, with one again owned by a private utility and the other by a municipal system. The assumed location was in the U.S. Southwest (Arizona or desert California), and, on the basis of earlier simulation analyses of the performance of photovoltaic plants using flat-plate silicon collectors, the plant capacity factor of the photovoltaic plants at this location was assumed to be 0.215 (indicating that the total annual production of electricity was 21.5% of the amount that would have been generated if the plant had been able to run at peak capacity for all 8760 hours of the year). In computing this capacity factor, an allowance was made for a 10% reduction in output as a result of dirt accumulation and overall degradation of collector performance. All of the plants were assumed to have a rated (peak) capacity of 200 MW.

1. Input Data

As was indicated in Section B, FAMS computes the total investment cost of the project, as of the date of initial operation, on the basis of input values for plant construction costs. The computation takes into account any inflation that occurs and allows for interest expense and accrual of dividends owed to equity stockholders. By contrast, the earlier levelized busbar cost analyses have all begun with an assumed value for the total investment cost of the plant, as of the date of initial operation. The goals of the DOE Photovoltaic Program, in the central station applications area, are also expressed in terms of a target value for the total investment cost. For the purposes of the present study, therefore, the FAMS input plant construction cost parameters were adjusted to yield a value of \$1600/kW_p (actually \$1645/kW_p), in 1980 dollars, as the output of the FAMS calculation of the total investment cost of a photovoltaic power plant

in an investor-owned utility, and $500/kW (actually $520/kW$_p$) as the computed investment cost of an oil-steam plant in an investor-owned utility. It was decided to use the same input parameters in the FAMS analysis of the economics of such plants in municipal systems. Because of the different debt/equity ratio and different effective cost of capital in these cases, the investment cost figures for the plants came out somewhat lower: $1538/kW$_p$ (1980 dollars) for the photovoltaic plant and $474/kW$_p$ (1980 dollars) for the oil-steam plant. Because these differences are likely to exist in real cases, they were retained in the analysis.

As implemented in this study, FAMS computes all costs and revenues in terms of nominal or current-year dollars, dollars of the year represented in the computation. The total investment cost of a power plant going on line in 1990, for example, is therefore the sum of some 1985 outlays (expressed in 1975 dollars), some 1986 outlays (in 1986 dollars), and so on, plus annual allowances (in current-year dollars) for the required return on these investments. To the extent that the rate used in computing these allowances for funds used during construction is equivalent to the internal discount rate of the utility company, this sum is the net present value (in 1990, and expressed in 1990 dollars) of all the outlays associated with construction of the plant. Conversion to 1980 dollars is accomplished in the analysis by dividing by the factor $(1 + e)^{10}$, where e is the assumed average annual inflation rate.

With one exception, the principal input parameters are listed in Table A-I-1, as are the values assigned to them in this study. The financial parameters (interest rate, allowed rate of return on rate base) reflect expected conditions in the post-1990 period, rather than those prevailing in the current high-inflation climate. The one important input that is not listed in the table is FLC, the cost of fuel in the year the plants go into operation (1990). This quantity was treated as a variable parameter in the analysis and assigned values ranging from $30/barrel to $50/barrel ($\approx$ 47-79 mills/kWh) in 1980 dollars. Since the current price of residual oil to utilities is already in the neighborhood of $30/barrel (April 1980 average for one Southwestern utility: $32.60/barrel), the lower end of this range

Table A-I-1 Input Parameters

Name	Description	Units	Value			
			Photovoltaic		Oil-Steam	
			Private	Muni	Private	Muni
DEPTM1	Plant depreciation time - book	Yrs	30	30	30	30
DEPTM2	Plant depreciation time - tax	Yrs	20	-	20	-
FDTXRT	Federal corporate income tax rate	%	46	-	46	-
STTXRT	State corporate income tax rate	%	9	-	9	-
SDTPCT	Starting debt to total capital ratio	%	50	100	50	100
SEQPCT	Starting equity to total capital ratio	%	50	0	50	0
INTRAT	Interest rate on debt	%	8	6	8	6
AROROB	Allowed rate of return on rate base	%	10	0	10	0
ITCRAT	Investment tax credit rate	%	10	0	10	0
PLTSIZ	Power plant capacity	MW	200	200	200	200
POWFAC	Plant capacity factor	%	21.5	21.5	60	60
IYEAR	Year of start of commercial operation	Yr	1990	1990	1990	1990
OPX	Operation and maintenance expense	mills/kWh	0	0	0	0
IDCP	Direction of construction period	Yrs	5	5	5	5
IPT	Present time	Yr	1980	1980	1980	1980
TCC	Total construction cost	$M	272	272	85	85
ESCRAT	Escalation rate per year	%/yr	6	6	6	6
PRTXCP	Property tax rate during construction	%	1.25	1.25	1.25	1.25
PRTXCO	Property tax rate during operation	%	2	2	2	2
INSURC	Insurance rate during construction	%	0.25	0.25	0.25	0.25
INSUR	Insurance rate during operation	%	0.25	0.25	0.25	0.25

is quite conservative. Furthermore, it was assumed in the computations that the oil price remains fixed in constant-dollar terms (i.e., rises at exactly the rate of general inflation) throughout the 30-year period of operation of the plants. This assumption, of course, introduces a further degree of conservatism into the analysis, since oil prices have increased rapidly, even in real terms (i.e., in terms of constant dollars), in recent years and are likely to continue rising at a rate faster than general inflation for many years to come.

2. Results

Some of the more interesting of the results that were obtained in the analysis are presented in Figures A-I-1 to A-I-4. In Figure A-I-1, the annual cost of service (top curve) associated with a photovoltaic power plant in an investor-owned utility is plotted as a function of time. This is the cost of generating electricity in the photovoltaic plant, in mills/kWh (current-year dollars, i.e., 1990 dollars in 1990, 1991 dollars in 1991, etc.) and, as is indicated in the future, is comprised of components allocated to the allowed return on rate base, taxes, insurance, and depreciation. The sharp rise in the cost after the first year of operation occurs because the investment tax credit is available only in the first year. The rapid decline in later years occurs because the contribution of the plant to the rate base (and the associated return on rate base and taxes on this return) drops as debt is paid off and equity capital returned. The dashed horizontal line in the figure represents the levelized cost of service as computed by FAMS and corresponds to an effective fixed charge rate of 14.5%.

The correspnding curves for the case of a photovoltaic plant in a municipal utility are shown in Figure A-I-2. The levelized value of the cost of service in this case corresponds to a fixed charge rate of 9.2%.

In Figures A-I-3 and A-I-4, the cost of service from a photovoltaic plant is compared to that for a new oil-fired plant, for various assumed values of the 1990 cost of oil (expressed in 1980 dollars). Figure A-I-3 represents the case where the utility is investor-owned, while Figure A-I-4

COSTS EXPRESSED IN CURRENT DOLLARS

PLANT CAPACITY:	200 MWp
LOCATION:	PHOENIX, ARIZONA
PLANT CAPACITY FACTOR:	0.215
DATE OF INITIAL OPERATION:	1990
CAPITAL COST:	$2945 / kWp
($1645 / kWp in 1980 dollars)	
RATE OF GENERAL INFLATION:	6% / yr
INTEREST RATE ON DEBT:	8%
RATE OF RETURN ON RATE BASE:	10%
INVESTMENT TAX CREDIT RATE:	10%

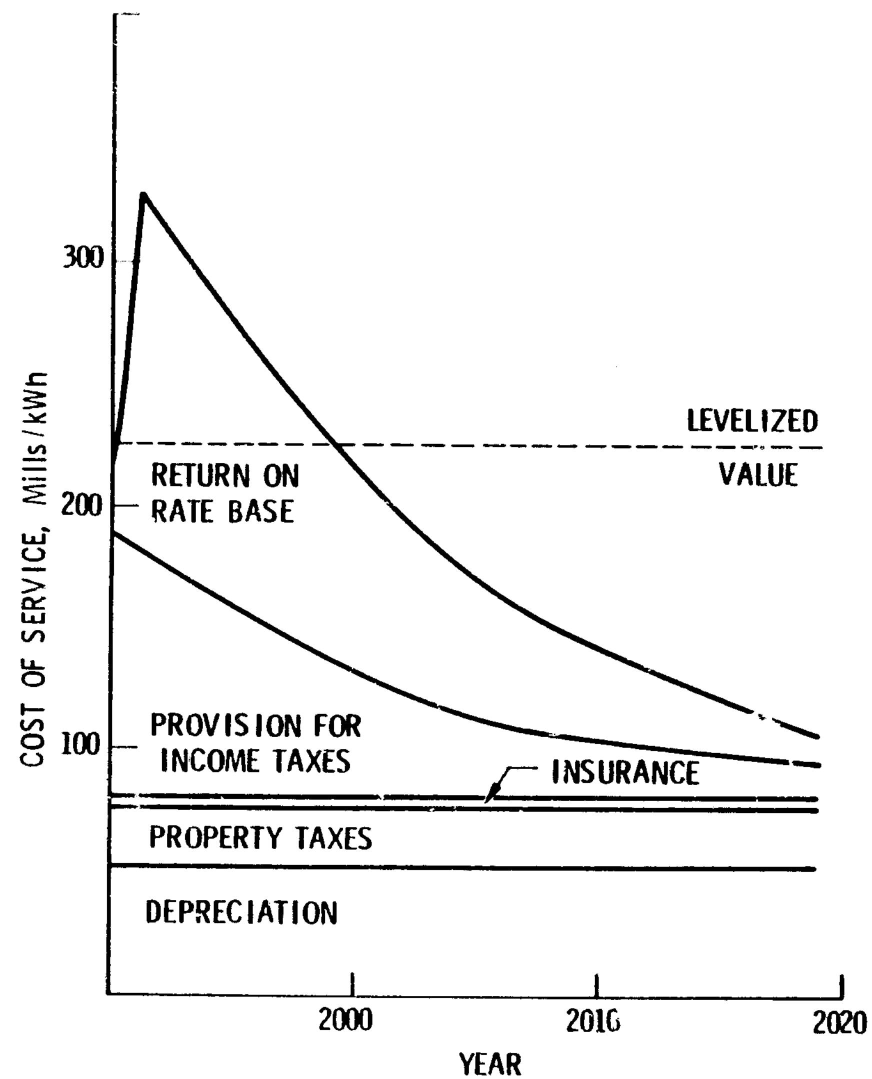


Figure A-I-1

Annual Cost of Service
Photovoltaic Power Plant in Investor-Owned Utility

COSTS EXPRESSED IN CURRENT DOLLARS

PLANT CAPACITY:	200 MWp
LOCATION:	PHOENIX, ARIZONA
PLANT CAPACITY FACTOR:	0.215
DATE OF INITIAL OPERATION:	1990
CAPITAL COST:	$2755/kWp
($1540/kWp in 1980 dollars)	
RATE OF GENERAL INFLATION:	6%/yr
INTEREST RATE ON DEBT:	6%

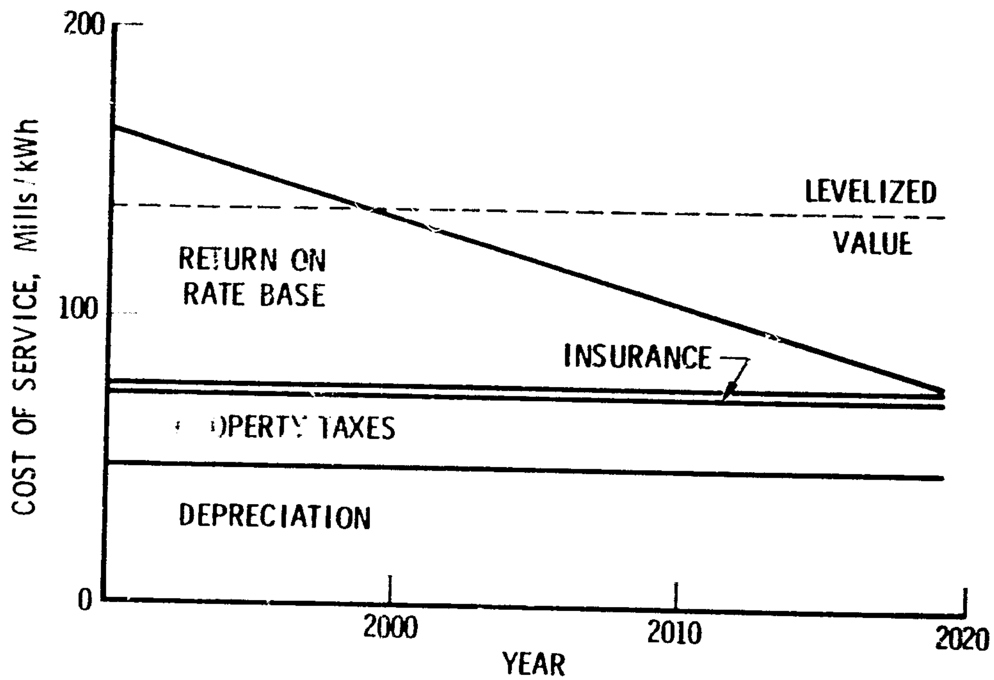


Figure A-' 2

Annual Cost of Service
Photovoltaic Power Plant in Municipal Utility

COST OF SERVICE EXPRESSED IN
TERMS OF CURRENT DOLLARS

REAL OIL PRICE (in constant dollars)
ASSUMED FIXED AT VALUES SHOWN

	PHOTOVOLTAIC	OIL-STEAM
PLANT CAPACITY	200 MWp	200 MW
CAPACITY FACTOR	0.215	0.6
CAPITAL COST		
1990 $/kW	2945	930
1980 $/kW	1645	520

RATE OF GENERAL INFLATION:	6%/yr
INTEREST RATE ON DEBT:	8%
RATE OF RETURN ON RATE BASE:	10%
INVESTMENT TAX CREDIT:	10%

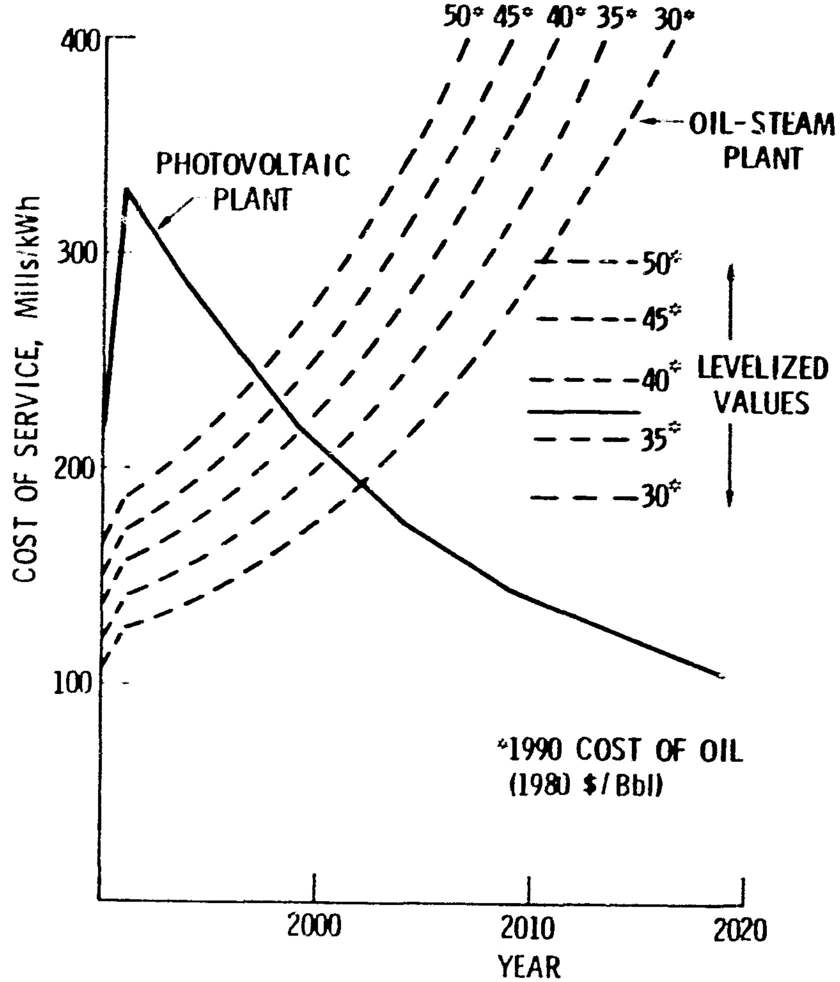


Figure A-I-3

Cost of Service Comparison:
Photovoltaic Power Plant vs. Oil-Steam Plant in Investor-Owned Utility

COST OF SERVICE EXPRESSED IN TERMS OF CURRENT DOLLARS

REAL OIL PRICE (in constant dollars) ASSUMED FIXED AT VALUES SHOWN

	PHOTOVOLTAIC	OIL-STEAM
PLANT CAPACITY	200 MWp	200 MW
PLANT CAPACITY FACTOR	0.215	0.6
CAPITAL COST		
1990 $/kW	2755	850
1980 $/kW	1540	475

RATE OF GENERAL INFLATION: 6%/yr
INTEREST RATE ON DEBT: 6%

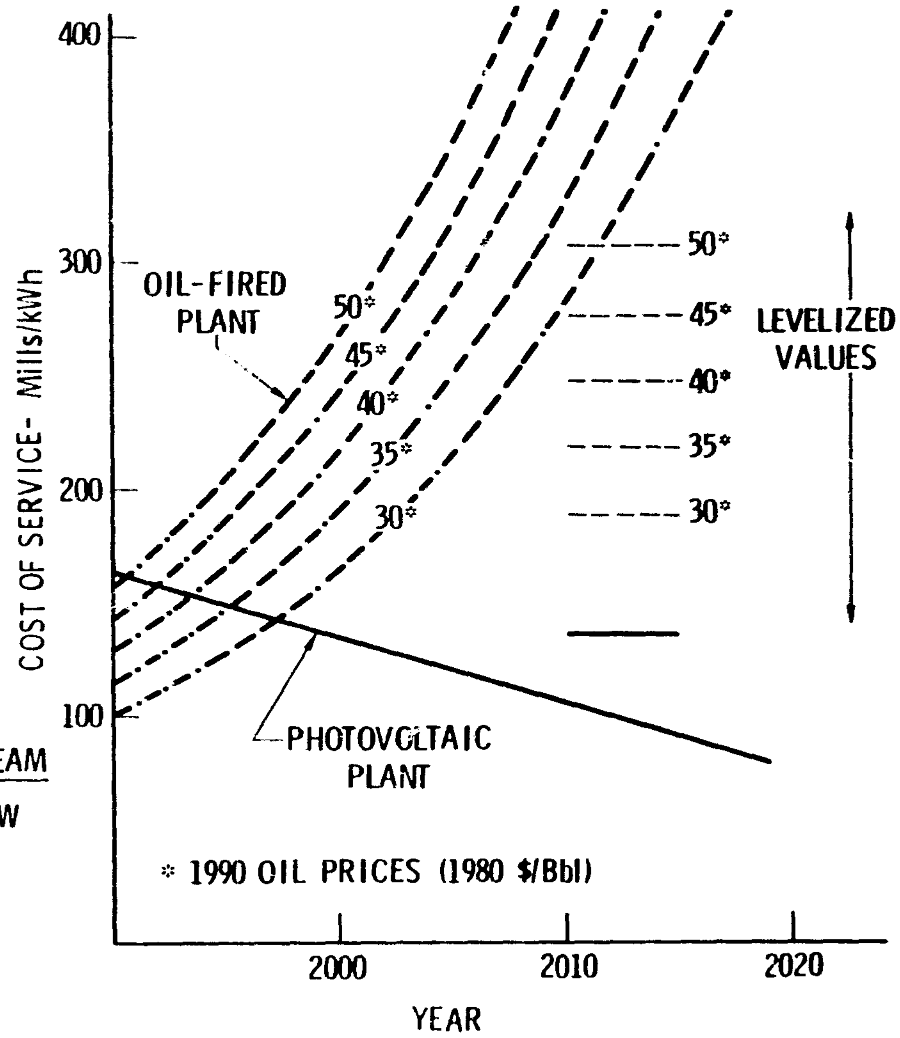


Figure A-I-4

Cost of Service Comparison:
Photovoltaic Power Plant vs. Oil-Steam
Plant in Municipal Utility

presents the corresponding comparison for a municipal utility. The horizontal lines in each figure represent the levelized value of the cost of service for the various examples. The effective fixed charge rate for the oil plant is 15.0% in the investor-owned utility case and 9.1% in the municipal case.

Figure A-I-3 indicates that, on the basis of levelized cost of service, a $1645/kW_p$ photovoltaic plant in a Phoenix investor-owned utility would be economically competitive with a new oil-fired plant if the oil price is greater than about $37/barrel. In the municipal utility case (Fig. A-I-4), the photovoltaic plant (at $1540/kW_p$) would be competitive even at oil prices well below the current $30/barrel. Both figures show, however, that the <u>unlevelized</u> cost of service for a photovoltaic plant is appreciably higher than that for an oil-fired plant during the first few years of operation.

D. Discussion

The results of this analysis indicate that, as expected, examination of the annual balance sheets associated with the construction and operation of photovoltaic and oil-steam plants reveal substantial differences that are not detectable in levelized-cost comparisons. In particular the high capital cost and resulting high early-year cost-of-service figures for a photovoltaic plant could conceivably cause significant cash-flow problems for a utility constructing such a plant. This circumstance could, in turn, lead a utility to choose some other form of generation even when a photovoltaic plant would be more economical on a life-cycle-cost basis.

It seems clear that such an outcome would be detrimental to the interests of the nation as a whole. The benefits of photovoltaic power generation -- especially its environmentally benign character and its dependence on an inexhaustible energy source -- are sufficient to justify subsidization even when the technology is not completely competitive in strictly economic turns. It is therefore all the more appropriate to consider government financial actions that might alleviate the early-year cash-flow problems that are connected with this technology when it is

economically competitive. Such tactics as the offering of low-cost government loans or the provision of loan guarantees that could reduce the cost of capital are among the possibilities. These and other possible government actions to address the problem should be given careful study and those judged most likely to be effective should be adopted.

ADDENDUM II

A PRELIMINARY LOOK AT THE OIL CONSERVATION MARKET OUTSIDE THE SUNBELT

A. Introduction

In the main part of this Final Report (Section III.D), a discussion was given of the consumption of oil and gas for electric power generation in the Sunbelt states (DOE Utility Industry Statistical Data Regions 4, 6 and 9) and estimates were made of the fraction of this consumption that is potentially displaceable by photovoltaic generation. In this Addendum, the discussion is extended to include the remainder of the United States. In Section B, an account is given of the consumption of oil and gas for electric power production in all 50 states, and in Section C estimates are made of the displaceable fraction of this consumption.

B. Oil and Gas Consumption for Electric Power Generation (1978)

In order to assess the magnitude of the U.S. oil-displacement potential of photovoltaic power, the FPC Form 4 data file was acquired. This file includes information on the capacity, monthly energy generation (for each fuel type), and monthly fuel consumption of each power plant in the United States. The data for the most recent year, 1978, were extracted from the file and organized by state, by DOE Utility Industry Statistical Data Region, and by type of utility (investor-owned, municipal or cooperative, state or federal project).

Some of these data are presented in summary form in Tables A-II-1 and A-II-2, which provide state-by-state listings, organized by Data Region, of the electric energy generated from oil and gas and of the consumption of oil and gas for this purpose. Table A-II-1 contains data on the total amount of electricity (in MWh) produced in 1978 in oil-fired or gas-fired generators in each state and in each region. These data are segregated by type of utility -- investor-owned utilities (IOU), municipal utilities and

Table A-II-1 Annual U.S. Electric Energy Generation from Oil and Gas (1978) - MWh

Region	State	Oil IOU[1)]	Oil M/C[2)]	Oil F/S[3)]	Gas IOU	Gas M/C	Gas F/S	% Oil	% Gas
1	CT	11,568	11	17	-	-	-	44.5	-
	ME	963	-	7	-	-	-	8.7	-
	MA	30,082	328	-	121	2	-	80.1	0.3
	NH	1,908	-	-	-	-	-	37.3	-
	RI	556	-	-	-	-	-	95.8	-
	VT	5	4	-	-	2	-	0.2	-
		45,082	343	24	121	4	-	53.5	0.1
2	NJ	16,657	102	-	73	-	-	53.1	0.2
	NY	48,861	103	2,658	100	-	-	44.1	0.1
		65,518	205	2,658	173	-	-	46.0	0.1
3	DE	4,349	486	-	140	14	-	66.4	2.1
	DC	1,781	-	-	-	-	-	100.0	-
	MD	10,977	83	-	40	3	-	30.6	0.1
	PA	16,224	-	2	30	3	-	12.7	-
	VA	15,281	6	23	69	13	-	35.2	0.2
	WV	800	-	-	1	-	-	1.2	-
		49,412	580	25	280	33	-	17.8	0.1
4	AL	56	-	472	592	82	-	0.7	0.9
	FL	34,958	10,984	5	11,080	3,164	61	48.6	15.1
	GA	3,429	-	-	453	-	9	6.2	0.8
	KY	104	34	-	106	-	-	0.2	0.2
	MS	11,195	722	-	3,175	334	-	60.6	17.9
	NC	969	-	3	-	-	-	1.5	-
	SC	3,882	-	43	454	-	-	8.8	1.0
	TN	-	-	2,366	-	-	-	3.9	-
		54,593	11,740	2,889	15,860	3,850	70	14.8	4.2

Table A-II-1 Annual U.S. Electric Energy Generation from Oil and Cas (1978) - MWh

Region	State	Oil IOU[1]	Oil M/C[2]	Oil F/S[3]	Gas IOU	Gas M/C	Gas F/S	% Oil	% Gas
5	IL	8,166	178	72	1,591	315	5	7.8	1.8
	IN	1,961	33	-	271	28	-	2.9	0.4
	MI	10,145	752	-	1,470	411	94	13.8	2.5
	MN	633	358	-	6	109	-	2.8	0.3
	OH	3,125	53	-	104	57	4	2.8	0.1
	WI	999	29	-	534	37	-	2.7	1.5
		25,029	1,403	72	3,976	957	103	6.0	1.1
6	AR	6,840	1,193	-	498	11	-	40.6	2.6
	LA	14,363	208	-	32,546	4,395	-	23.6	59.7
	NM	203	12	1	5,072	540	107	1.1	28.6
	OK	98	19	-	32,575	2,900	119	0.3	86.2
	TX	3,420	578	1	130,008	12,383	4,065	2.1	75.3
		24,924	2,010	2	200,699	20,229	4,291	8.0	66.8
7	IA	267	166	11	478	71	23	2.5	3.2
	KS	2,197	294	-	7,080	2,631	-	10.1	39.3
	MO	932	324	-	1,098	1,034	-	2.7	4.6
	NE	-	244	403	-	458	535	4.3	6.5
		3,396	1,028	414	8,656	4,194	558	4.6	12.9
8	CO	334	44	-	1,904	344	-	1.7	10.4
	MT	35	-	-	84	-	-	0.2	0.5
	ND	10	26	-	1	-	-	0.3	-
	SD	102	-	-	2	-	-	1.0	-
	UT	89	2	-	545	21	-	0.9	5.6
	WY	87	-	-	-	-	3	0.4	0.3
		657	72	-	2,595	365	3	0.8	3.3

Table A-II-1 Annual U.S. Electric Energy Generation from Oil and Gas (1978) - MWh (Cont'd)

Region	State	Oil IOU[1]	Oil M/C[2]	Oil F/S[3]	Gas IOU	Gas M/C	Gas F/S	% Oil	% Gas
9	AZ	1,677	13	1,380	3,514	495	1,027	10.0	16.4
	CA	50,945	9,104	693	25,953	3,896	39	43.0	21.1
	HI	6,241	-	-	-	-	-	91.3	-
	NV	1,681	-	-	2,094	4	-	12.9	16.1
		60,544	9,117	2,073	31,561	4,395	1,066	37.4	19.3
10	AK	43	372	-	-	1,698	-	13.0	53.0
	ID	2	-	-	3	-	-	-	-
	OR	52	-	-	-	-	-	0.2	-
	WA	24	-	-	5	-	-	-	-
		121	372	-	8	1,698	-	1.2	1.5
Total		329,276	26,870	8,157	263,929	35,455	6,091	15.9	13.3

1) IOU = Investor-owned utilities
2) M/C = Municipal utilities and cooperatives
3) F/S = Federal/state projects

cooperatives (M/C), and state and federal projects (F/S). Also shown in this table are the percentages of the total annual electricity requirements of the state or region that are provided by oil-fired or gas-fired generators.

In Table A-II-2 are presented the corresponding figures for the consumption of oil and gas for the generation of electricity. The oil data are segregated by type of oil -- residual oil, distillate, diesel fuel -- and are expressed in barrels/day. The gas data are expressed in terms of "equivalent" barrels/day, equivalent in terms of Btu content.

These data tend to confirm the earlier conclusion that the most promising areas of the U.S. in terms of oil-conservation potential are in the Sunbelt. Not only is the average insolation high, so that photovoltaic performance is good, but there is a very high usage of oil and gas for power generation. The states of California, Florida, Hawaii, and Mississippi are particularly attractive in this respect, with the former two states having the additional advantage of substantial oil-displacement potential in municipal utilities. (In municipal utilities, the lower effective cost of capital increases the attractiveness of capital-intensive technologies like photovoltaics.) In terms of potential photovoltaic displacement of gas, the state of Texas, Oklahoma, and Louisiana continue to appear most promising. In addition, the state of Kansas (which is in, or bordering, the Sunbelt although not included in Regions 4, 6, or 9) also shows considerable promise.

As oil prices rise and photovoltaic system prices fall, however, photovoltaic technology will become economically competitive in regions with poorer insolation. When this occurs, Tables A-II-1 and A-II-2 show that there will then be a very substantial oil-displacement potential in New York, New Jersey, and in the New England states -- especially Massachusetts and Rhode Island. In the Middle Atlantic Region, Delaware and the District of Columbia also appear to be attractive areas for displacing oil consumption by photovoltaic generation.

Table A-II-2 Consumption of Oil and Gas for Electric Power Generation - 1978
Barrels/Day

Region	State	Oil: Residual	Oil: Distillate	Oil: Diesel	Oil: Total	Gas
1	CT	53,868	163	49	54,080	-
	ME	4,771	11	62	4,844	-
	MA	131,604	1,588	415	133,607	711
	NH	9,585	20	- -	9,605	-
	RI	3,166	--	16	3,182	
	VT	27	41	12	80	19
		203,021	1,823	554	205,398	729
2	NJ	72,432	8,328	1	80,761	351
	NY	238,862	4,030	537	243,429	558
		311,294	12,358	538	324,190	909
3	DE	22,059	482	-	22,541	678
	DC	9,958	643	-	10,601	-
	MD	51,889	1,690	372	53,951	237
	PA	71,871	9,971	138	81,980	200
	VA	72,657	2,890	101	75,648	446
	WV	4,111	5	-	4,116	6
		232,545	15,681	611	248,837	1,567
4	AL	244	2,945	-	3,189	3,202
	FL	197,668	13,014	807	211,489	72,164
	GA	14,612	3,512	1	18,125	2,685
	KY	472	185	-	657	551
	MS	54,177	934	-	55,111	19,747
	NC	3,582	1,771	-	5,353	2
	SC	15,517	2,350	-	17,867	2,367
	TN	-	14,182	-	14,182	-
		286,272	38,893	808	325,973	100,7[illegible]
5	IL	35,535	11,107	454	47,096	10,303
	IN	8,885	2,127	161	11,173	1,435
	MI	52,831	1,578	1,534	55,943	16,590
	MN	3,613	1,764	732	6,109	701
	OH	10,177	9,143	299	19,619	1,434
	WI	3,750	3,284	186	7,220	3,795
		114,791	29,003	3,366	147,160	34,25[illegible]
6	AR	36,970	731	11	37,712	3,193
	LA	67,905	42	130	68,077	168,576
	NM	1,165	18	47	1,230	28,894
	OK	374	139	90	603	156,736
	TX	18,470	262	199	18,931	680,675
		124,884	1,192	477	126,553	1,040,07[illegible]

Table A-II-2 Consumption of Oil and Gas for
Electric Power Generation - 1978
Barrels/Day (Cont'd)

Region	State	Residual	Distillate	Oil Diesel	Total	Gas
7	IA	1,039	1,329	749	3,117	3,733
	KS	10,756	1,282	793	12,831	53,914
	MO	3,214	3,219	869	7,302	12,451
	NE	2,543	564	357	3,464	5,859
		17,552	6,394	2,768	26,714	75,957
8	CO	1,522	826	109	2,457	13,443
	MT	258	10	-	268	415
	ND	130	1	70	201	10
	SD	421	140	98	659	11
	UT	484	-	13	497	3,459
	WY	422	-	39	461	325
		3,237	977	329	4,543	17,663
9	AZ	11,254	4,133	16	15,403	24,830
	CA	269,805	7,243	100	277,148	137,975
	HI	27,032	1,008	1,115	29,155	-
	NV	7,674	49	16	7,739	9,931
		315,765	12,433	1,247	329,445	172,736
10	AK	2	972	1,458	2,432	11,156
	ID	-	12	-	12	17
	OR	-	386	1	387	-
	WA	85	35	-	120	25
		87	1,405	1,459	2,951	11,198
TOTAL		1,609,448	120,159	12,157	1,741,764	1,455,809

C. Substitution of Photovoltaic Generation for Oil/Gas Consumption: An Upper Limit Estimate

In the main body of this report (Section III D), estimates were made (and presented in Fig. 5) of the fraction of Sunbelt oil-steam capacity for which photovoltaic generation would be a cost-effective alternative. Reported in this Addendum are the results of some additional calculations of the same general type, except that the analysis was extended to include the entire U.S. and different assumptions were made about the future trend of oil prices.

As before the 1978 consumption of oil for electricity generation was taken as a measure of the total oil-displacement market in future years. Two different photovoltaic system price figures were considered -- $1.60/$W_p$ and $1.10/$W_p$ (both in 1980 dollars) -- and it was assumed that the price of oil for electricity generation would rise from the 1980 figure of $30/barrel at a real rate (i.e., in addition to general inflation) of 2%/year. As time goes on, under these assumptions, photovoltaic generation becomes competitive first in municipal utilities and cooperatives in high insolation states but later in federal/state projects and investor-owned utilities and in states with lower average insolation. An increasing fraction of the total oil-displacement market therefore becomes accessible.

Figure A-II-1 illustrates, in bar-chart, form, the growth in magnitude of this accessible market as time passes and oil prices rise (for fixed photovoltaic system price, in 1980 dollars). Even conceptually, not all of this oil consumption is displaceable by photovoltaics, of course, since a significant fraction of it occurs in non-daylight hours; the values shown in the figures do, however, provide an upper bound on the actually realizable market. For each year, the right-hand bar represents the market (subdivided among municipal/cooperatives, federal/state projects, and investor-owned utilities) in which $1.10/$W_p$ photovoltaic systems would be competitive. (There is no right-hand bar in the 1986 case because the National Photovoltaic Program does not expect system prices in this range until 1990 at the earliest). The left-hand bars represent the case where the capital cost of a photovoltaic power plant is $1.60/$W_p$.

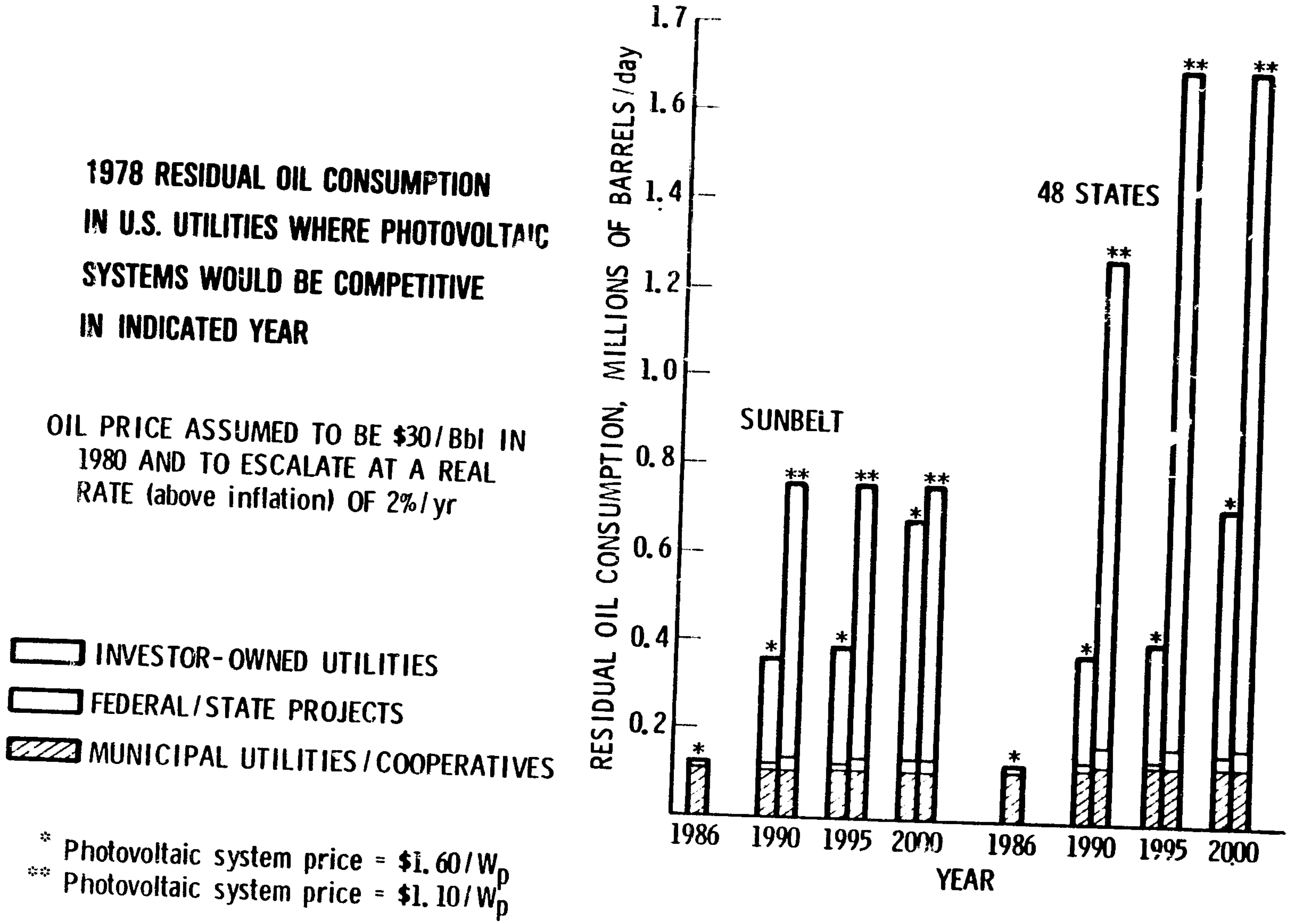


Figure A-II-I
Total Utility Oil-Conservation Market: An Upper Limit

The bars in Fig. A-II-1 indicate that, at least until 2000, most of the oil-displacement market that is accessible to $1.60/$W_p$ photovoltaic systems is in the Sunbelt. (This result is, of course, dependent on the assumed rate of increase in oil prices. If the real oil-price escalation rate exceeds 2%, more of the non-Sunbelt market will come into reach.) If photovoltaic system prices in the $1.10/$W_p$ range are achieved, however, nearly half of the potential oil-conservation market is the less-sunny regions of the country, principally in the Upper Atlantic and New England Regions.

ADDENDUM III

PRELIMINARY TECHNOLOGY DEVELOPMENT REQUIREMENTS FOR CENTRAL STATION APPLICATIONS

A. Introduction

This Addendum presents preliminary cost goals for photovoltaic central station subsystems as well as some preliminary analytical results relative to the appropriate DC voltage and power conditioning size for an element or "system module" of a photovoltaic central station. It is expected that system engineering studies conducted during 1980 and by industry/utility teams during 1981 will update the information presented in this document.

B. Subsystem Preliminary Cost Goals

The Photovoltaic Central Station Plan (Ref. A-2) consists of two elements, namely

1) Development of systems that use Baseline Technology components ($.70/W modules) that have a total system cost of $1.50 - 2.00/W. It is expected that such systems would be cost-effective in reducing oil consumption in Sunbelt utilities by the late 1980s.

2) Development of systems that use Advanced Technology Components ($.15 - .40/W modules) that have a total system cost of $1.10 - 1.30/W. Such costs are required to compete with new coal-fired plants. It is expected that such photovoltaic systems will be available by 1990.

Baseline Technology flat plate and concentrator array development is in progress at JPL in the Low Cost Solar Array Program and at Sandia in the Concentrator Development Program. It is expected that Technology Ready (TR) arrays will be available at the end of 1982 and Commercially Ready arrays will be available four years later (Ref. A-3).

In addition to photovoltaic collectors, technology development effort is required in three main categories: collector support structures and installation, power conditioning and control, and energy storage. The goals of these efforts are to make possible BOS costs that are consistent with

total system costs of $1.50-2.00/W_p$ (baseline collector technology) and $1.10-1.30/W_p$ (advanced collector technology). Since the price goal for baseline technology collectors is $0.70/W_p$ while that for advanced technology collectors is $0.15-0.40/W_p$, it is clear that the requirements on BOS costs are essentially the same in the two cases.

Detailed cost goal allocations (assigning subsystem cost goals that are consistent with overall system cost goals) have not yet been carried out for photovoltaic central power plants. A number of preliminary studies (see attached list of completed studies) have indicated, however, that the total cost of collector support structures for non-tracking arrays (including the cost of assembling the collector onto the support and installing the assembled array in the field) should be no more than about $25/m^2, if system cost goals are to be met. One of the current goals in this area, accordingly, is to develop non-tracking support structure concepts that can be manufactured and installed at a total cost of $25/m^2 ($\sim$ $0.25/W_p$) or less. A number of candidate concepts have been identified, but development work remains to be done. Automated machinery to reduce the cost of field installation must also be developed.

The power conditioning and control portion of the BOS includes the DC-AC inverter, control logic, switch gear, and all other equipment required to transform the DC output of the collectors into AC power of the correct frequency, phase, and harmonic purity for delivery to the output transformers of the power plant. Equipment needed for controlling the interchange of energy with electric storage, if any, is also included. The basic technology to accomplish these functions appears to be well in hand, but hardware to meet the specific requirements of a photovoltaic power plant has not yet been constructed. The role of the TD effort in this area will be to promote the design and construction of the required equipment. It will be a coordinated activity, carried out jointly by the Division of Distributed Solar Technology (Photovoltaics Branch) and the Division of Electric Energy Systems, as described in Appendix C of the MYPP (Ref. A-3). Related activities of the Electric Power Research Institute and the DOE Energy Storage Systems Program (in connection, for example, with the Battery Energy Storage Test project) will be closely monitored.

Because cost goal allocations have not yet been made, firm cost goals for the power conditioning/control portion of the BOS have not been assigned. Earlier studies indicate, however, that this cost should not be much greater than $100/kW if system cost goals are to be met. Achievement of prices in this range is believed to be possible if proper attention is given to cost factors in the design and if sufficient production volume is achieved. A preliminary analysis of the appropriate size (in kW) of power conditioning required for central station applications is described in Section C of this Addendum.

The system definition studies so far conducted have all indicated that the inclusion of dedicated electric energy storage subsystems in photovoltaic power plants is unlikely to be cost-effective. While such plants have somewhat greater value to a utility system than do systems without dedicated storage, the extra value contributed by the storage is smaller than the expected incremental cost. If storage is to be included at all, furthermore, the studies indicate that it could more profitably be used as an adjunct to the entire utility system than as an element of a photovoltaic power plant. For these reasons, the current TD effort under this Central Station Applications Implementation Plan does not include work on the development of storage equipment. Progress in the program of the DOE Energy Storage (STOR) Division will be monitored, and if cost reductions gr t enough to alter the conclusions of the studies referred to above appear possible (life-cycle cost, for 30 years of service, less than $50/kWh) the question of including storage TD in this program should be reconsidered.

Table A-III-1 summarizes the preliminary cost goals, their basis and major issues for each subsystem and cost area.

Table A-III-1

Central Station Subsystem Preliminary Cost Goals

Subsystem	Cost Goals ($\$/W_p$) Early Oil Market	Cost Goals ($\$/W_p$) Long Term Market	Basis	Major Issues
o Array				
- Flat Plate Module	.70	.15-.40	Program Goal	Efficiency
- Supporting Structure Installation	.25	.25	Industry Studies	Configuration(s), Installation Procedures
- Concentrator or Total for Flat Plate	.95	.40-.65	Program Goal	Efficiency, Thermal Energy Use
o Power Conditioning	.10	.10	Industry Studies	Size, Input DC Voltage
o Site Purchase and Preparation	.02-.10	.02-10	Industry Studies	
o Wiring, Switches	.03-.10	.03-10	Industry Studies	DC Voltage
Subtotal	1.1-1.25	.55-.95		
o Other (Spares, Contingencies, Engineering, Interest During Construction, Other Facilities, Marketing)	.4-.7	.4-.7	Industry Studies	
Total Capital Cost	1.50-1.95	.95-1.65		

C. A Preliminary Investigation of Engineering Trade-offs Relative to Subfield Size and Voltage

Except for the very smallest units, photovoltaic systems are inherently modular, and photovoltaic central power plants are expected to exhibit this characteristic to a high degree. In all of the plant designs that have so far been developed, the complete system is composed primarily of a number of identical modular building blocks. In each of these system elements, a segment (subfield) of the total collector field is centered about a power conditioning unit (PCU) that inverts the DC output of the collector subfield to AC and transforms it up to the required internal plant bus voltage. The outputs of these separate elements are then brought together, perhaps transformed up to still higher voltage, and dispatched into the utility grid.

The most appropriate size (and power output) of each subfield and the optimum DC voltage at the PCU input can only be established by examining the associated cost/performance trade-offs. Even a cursory study of this problem, furthermore, reveals that another parameter of interest is the allowable energy loss (ohmic loss) in the DC wiring. The specification of optimal values for these parameters is necessary in order to identify the requirements for development of central station PCU technology. Although detailed design studies will be required before these specifications can be defined with a high degree of confidence, it has been considered appropriate to conduct a preliminary investigation of some of the more important trade-offs with the objective of, at least, clarifying the sensitivity of system cost to the choice of these parameters. A brief description of this initial analysis is presented below. The details of the calculation are described more fully in the Appendix.

The study that was performed focused on the dependence of the cost of a complete system module (collector subfield, DC conductors, power conditioning unit, and associated switchgear) on three parameters: output power, DC voltage, and DC loss factor (the ratio of the DC losses to the DC output of the subfield). An attempt was made to determine optimal values of these

parameters and to assess the sensitivity of the cost to variations from the optima. By necessity, these analyses neglected some rather important factors. Since no information was available about the dependence of PCU cost and performance on power level or DC voltage, these considerations were omitted from the analysis. (The PCU cost was simply assumed to be independent of power or voltage rating.) Limitations of time also presented consideration of variations in switchgear costs with these same parameters. It must further be noted that the values used for the dependence of collector cost on DC voltage are based on numbers obtained in an earlier study (Ref. A-4) and were not arrived at independently. For these reasons, the analysis must clearly be considered as only preliminary, and final definition of preferred power level and DC voltage must await a more detailed analysis that incorporates additional information not now available to us.

The results of these computations are displayed in Figure A-III-1, where the cost of a system module is plotted as a function of DC voltage level, with ohmic loss factor (the ratio of ohmic power loss to total DC power), X, set equal to 0.01 and power level, P, treated as a variable parameter. The cost rises sharply at the low-voltage end of the scale because of the cost of the heavier DC conductors that are needed in order to maintain constant X. At the high-voltage end, the cost rises gradually because of the increased cost of DC insulation. For these computations, the cost of the photovoltaic modules was assumed to be $0.70/$W_p$, the cost of support structure and installation to be $25/$m^2$, and the overall efficiency to be 13.5%. The other assumptions, and the procedures used, are described in the Appendix, as noted above.

In Figure A-III-2, the cost of a system module is again presented as a function of DC voltage, with output power set at 1 MW and the ohmic loss factor treated as a parameter. In this case, the trade off is between the cost of copper (which increases when the ohmic loss factor is reduced) and the cost of the incremental collector area needed to make up for the ohmic losses. As is demonstrated in the Appendix, it is possible to compute optimal values of the DC voltage and the ohmic loss factor when the power output is given. For the case shown in Figure A-III-2 (P = 1 MW), the optimum DC voltage is ~1200V and the optimal ohmic loss factor is 0.0044.

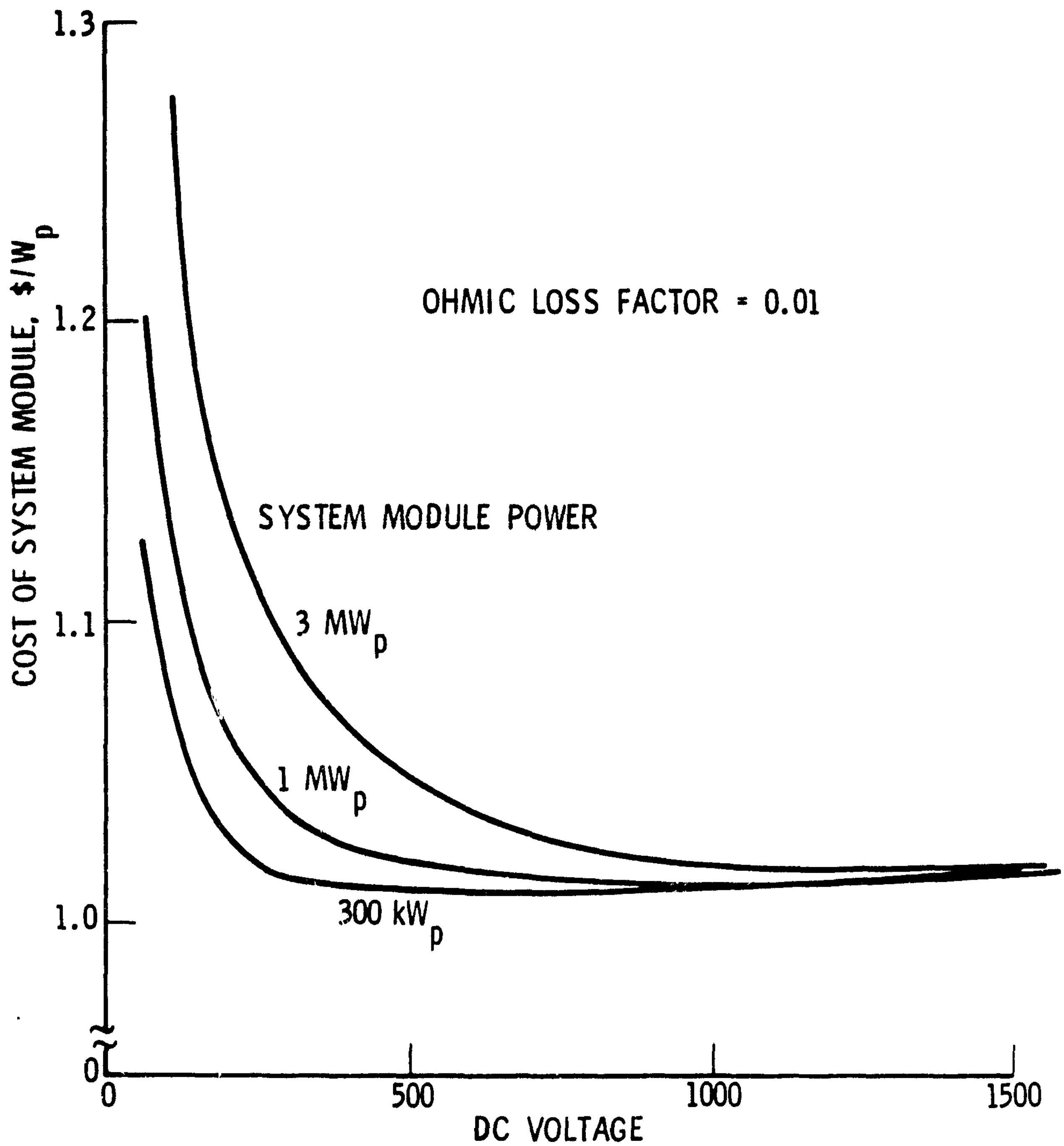


Figure A-III-1

System Module Cost as a Function of
DC Voltage and Power Output

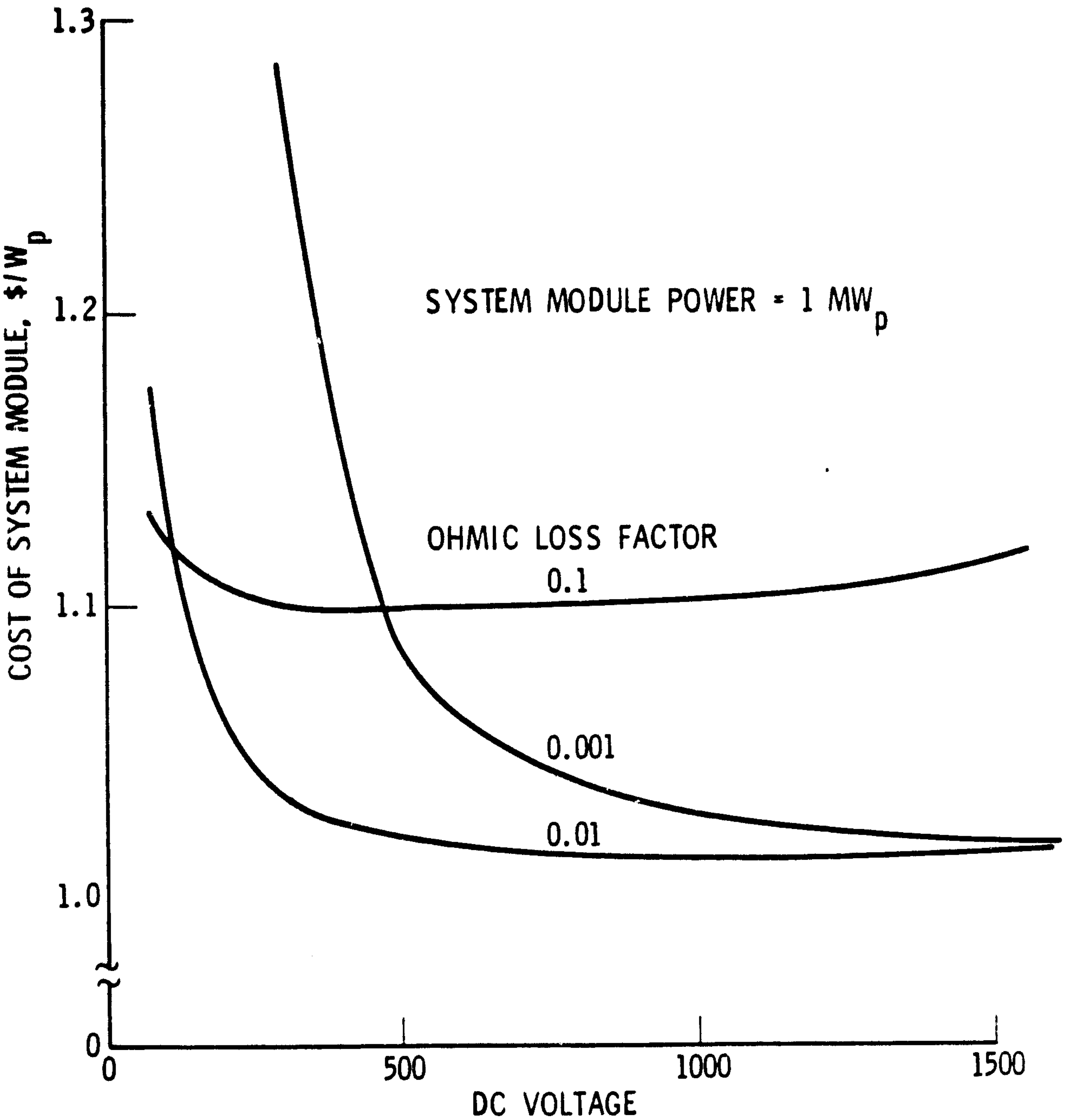


Figure A-III-2

System Module Cost as a Function of
DC Voltage and Ohmic Loss Factor

The principal message that can be obtained from these results is that the cost of a system module is relatively insensitive to the parameters considered, except at low voltages and at high loss factors. The trade-offs considered in this limited analysis have not led, therefore, to the identification of any major constraints on the choice of PCU voltage level or power rating, although they do suggest that higher power ratings call for higher DC voltages. There appear to be no significant cost impacts that would keep one from building a central station power plant around relatively small power conditioning units operating at DC voltages in the range of 300-600 V.

These conclusions are, of course, dependent on the assumptions that were made in the analysis. They may require revision when other factors are taken into account -- in particular, any voltage dependence of the cost and performance of PCUs or switchgear. It seems likely that the cost of switchgear will increase with voltage, thereby driving the optimal voltage levels lower. On the other hand, PCU efficiency and cost-effectiveness may well increase with voltage and power level and therefore provide a counterbalancing influence toward higher voltage.

APPENDIX TO ADDENDUM III

Dependence of System Module Cost on Power Level, DC Voltage, and Ohmic Loss Factor

It is assumed that a photovoltaic central station power plant will be composed of a number of modular elements each of which contains a portion (subfield) of the total collector field, a power conditioning unit (PCU), switchgear, and the requisite DC cabling. The collector subfield, in turn, will be made up of a number of strings of photovoltaic cells connected in series and generating the subfield DC voltage. These strings will be connected, in parallel, to the PCU.

Consider one such system element and let

P	=	peak DC power from subfield (watts)
n	=	number of (series) strings connected in parallel
P_j	=	peak DC power from jth string (watts)
I_j	=	peak DC current from jth string (amperes)
V	=	DC voltage (volts)
ℓ_j	=	length of DC conductor from jth string to PCU, including return circuit (meters)
R_j	=	electric resistance of ℓ_j (ohms)
X_j	=	ohmic loss factor for jth string (ratio of the string ohmic losses to P_j)
σ	=	resistivity of copper (ohm-m)
ρ	=	density of copper (lb/m^3)
α	=	cost of copper cabling (dollars/lb)
d_j	=	diameter of copper conductor from jth string (meters)

The cost of the DC cabling associated with the jth string is

$$C_{wj} = \frac{\pi}{4} d^2 \ell_j \rho \alpha \tag{1}$$

and the ohmic loss in ℓ_j is given by

$$X_j\, P_j = I_j^2\, R_j = P_j^2\, R_j/V^2$$

$$= (P_j^2\,/V^2)\ (4\sigma\ell_j/\pi\, d_j^2)$$

$$d_j^2 \quad = (4\,\sigma\,\ell_j\,P_j)\ /\ (\pi V^2 X_j) \qquad (2)$$

If the value of d_j^2 in (2) is substituted into Equation (1), we have

$$C_{wj} = (\sigma\,\ell_j^2\ \ P_j\,\rho\,\alpha)/\ (X_j V^2)$$

The total wiring cost for the subfield is then

$$C_w = \sum_{j=1}^{n}\ C_{wj} = \ (\sigma\rho\alpha/V^2)\sum_{j=1}^{n}\ (\ell_j^2\,P_j/\ X_j)$$

Let us assume that all strings are identical, so that

$$P_j = P/n$$

and that the ohmic loss factors are the same for all strings (implying that conductor size is larger for strings farther from the PCU), so that

$$X_j = X$$

It then follows that

$$C_w = \frac{\sigma \rho \alpha P}{n\, V^2 X} \sum_{j=1}^{n} \ell_j^2$$

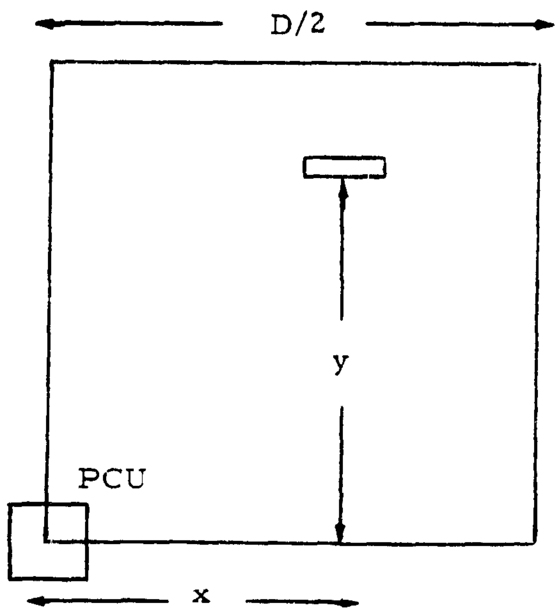
$$= \frac{\sigma \rho \alpha P}{V^2 X} \langle \ell_j^2 \rangle \qquad (3)$$

where

$$\langle \ell_j^2 \rangle = \frac{1}{n} \sum_{j=1}^{n} \ell_j^2$$

is the average value of the squares of the lengths of conductors from the n strings of cells.

In order to compute an approximate value for $\langle \ell_j^2 \rangle$, we take advantage of the fact that for the range of subfield sizes under consideration ($> 100\ kW_p$), n is very large. We assume that the subfield is approximately in the shape of a square, of side D (meters), with the PCU at the center, as indicated in the drawing. It seems likely that the cabling will be laid in trenches, and we assume that these trenches will be along the y-direction, in general, with all of the current in each trench being brought to the PCU along the x-axis. (Other cabling arrangements might, of course, be envisioned, but a little study will convince the reader that the resulting value of $\langle \ell_j^2 \rangle$ will not be very different).



Then

$$<\ell_j^2> = \left(\frac{2}{D}\right)^2 \int_0^{D/2} \int_0^{D/2} 4\ (x+y)^2 dx\ dy$$

$$= 7\ D^2/6$$

When this value is substituted into Equation 3, we obtain

$$C_W = (7\sigma\ \rho\ \alpha\ PD^2/\ (6\ V^2\ X) \tag{4}$$

Now the maximum power output, P, of the subfield can be expressed in the form

$$P = \eta(10^3)\ a\ (1-X) = 10^3\eta\ \ FD^2\ (1-X) \tag{5}$$

where

η = collector efficiency

a = collector surface area (m^2)

$F = a/D^2$ = ratio of collector area to total subfield area.

If we combine Equations 4 and 5 to eliminate D^2, we obtain

$$C_W = \frac{7\sigma\ \rho\ \alpha\ P}{6\ V^2\ X} \cdot \frac{P}{10^3\eta\ F(1-X)}$$

$$= \frac{7\sigma\ \rho\alpha P^2\ (10^{-3})}{6\eta\ F\ V^2\ X\ (1-X)} \tag{6}$$

The cost of the entire system module can then be obtained by adding this wiring cost figure to the cost of the collectors, the cost of the PCU, and the cost of the required switchgear. Utilizing Equation 5, we can represent the cost of the collector in the form

$$C_c = (A + B + mV)\ a = (A + B + mV) \cdot \frac{10^{-3}P}{\eta(1-x)} \qquad (7)$$

where

A = cost of collector modules ($\$/m^2$)

B = voltage-independent cost of collector support structure, installed, ($\$/m^2$)

m = coefficient relating voltage to voltage-dependent portion (electric insulation) of cost of collector structure ($\$/m^2$-V)

V = voltage (volts)

In the absence of information about the voltage dependence of the costs of power conditioning units or switchgear, these cost elements were treated as independent of voltage and represented by

C_{PCU} = cost of power conditioning unit

C_{sw} = cost of switchgear.

These costs were expressed in the form

$$C_{PCU} + C_{sw} = \beta P$$

where the coefficient β is expressed in dollars/watt.

Then the total cost of the system module is

$$C_M = (A + B + mV)\frac{10^{-3}P}{\eta(1-X)} + \frac{7\sigma\rho\alpha P^2(10^{-3})}{6\eta F V^2 X(1-X)} + \beta P \qquad (8)$$

We can obtain an expression for the optimum DC voltage by differentiating this expression with respect to V and setting the result equal to 0. In this way we obtain

$$\frac{\partial C_M}{\partial V} = \frac{10^{-3}\ Pm}{\eta(1-X)} - \frac{7\sigma\rho\alpha P^2(10^{-3})}{3\eta FX\ (1-X)\ V^3} = 0 \tag{9}$$

$$V_{opt} = \left(\frac{7\sigma\rho\alpha P}{3m\ FX}\right)^{1/3} \tag{10}$$

Equation 8 can also be used to obtain an optimal value for the loss factor X. To simplify the process, we write Equation 8 in the form

$$C_M = \frac{Q_1}{1-X} + \frac{Q_2}{X\ (1-X)} + \beta P \tag{11}$$

and

$$\frac{\partial C_M}{\partial X} = \frac{Q_1}{(1-X)^2} + \frac{(2X-1)\ Q_2}{(1-X)^2\ X^2} = 0$$

when $$Q_1 X^2 + 2\ Q_2 X - Q_2 = 0$$

Thus $$X_{opt} = \frac{-Q_2}{Q_1} \pm\sqrt{\left(\frac{Q_2}{Q_1}\right)^2 + \frac{Q_2}{Q_1}} \tag{12}$$

In general,

$$\frac{Q_2}{Q_1} << 1$$

so that

$$X_{opt} \sim \left(Q_1/\ Q_2\right)^{1/2} = \left[\frac{7\,\sigma\,\rho\,\alpha P}{6\ FV^2\ (A + B + mV)}\right]^{1/2} \qquad (13)$$

Example:

σ	=	1.724 (10^{-8}) ohm - m
ρ	=	19.58 (10^3) lb/m^3
α	=	\$1.70/lb
η	=	0.135
F	=	0.2
A	=	\$120/m^2
B	=	-0.441/m^2
m	=	\$8.82 (10^{-4})/m^2 -V
β	=	\$0.10/W_p

The values for B and m are derived from the results of the Bechtel study (Ref. A-4) for the case of mylar insulation.

In this case, Equation 8 becomes

$$C = 0.886\ (1 + 7.4\ (10^{-6})\ V) + 2.47\ (10^{-5})\ \frac{P_2}{V^2X\ (1-X)} + 0.1\ P \qquad (14)$$

while Equations 10 and 13 become

$$V_{opt} = 1.965\ (P/X)^{1/3} \qquad (15)$$

and

$$X_{opt} = 5.29\ (10^{-3})\ (P/V^2)^{1/2} \tag{16}$$

(In Equation 16, we have neglected the small mV term that originated in the expression for collector cost.)

These latter two equations can be combined to give expressions for the absolute optima, i.e., the value for V_{opt} at $X = X_{opt}$ and the value for X_{opt} at $V = V_{opt}$. The results are

$$V_{opt} = 37.9\ P^{1/4}$$

$$X_{opt} = 1.40\ (10^{-4})\ P^{1/4}$$

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